February 2, 2015

Randall Richert
Phillips 66 Company
Billings Refinery
401 South 23rd Street
P.O. Box 30198
Billings, MT 59107

Dear Mr. Richert:

Montana Air Quality Permit #2619-32 is deemed final as of January 31, 2015, by the Department of Environmental Quality (Department). This permit is for Phillips 66 Company's Vacuum Improvement Project. All conditions of the Department's Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

For the Department,

Julie A. Merkel
Air Permitting Supervisor
Air Resources Management Bureau
(406) 444-3626

Shawn Juers
Environmental Engineer
Air Resources Management Bureau
(406) 444-2049

JM:SJ
Enclosure

Montana Department of Environmental Quality
Permitting and Compliance Division

Montana Air Quality Permit #2619-32

Phillips 66 Company
Billings Refinery
401 South 23rd Street
P.O. Box 30198
Billings, MT 59107

January 31, 2015

MONTANA AIR QUALITY PERMIT

Issued to: Phillips 66 Company Billings Refinery P.O. Box 30198 Billings, MT 59107-0198	MAQP: #2619-32 Application Complete: 11/18/2014 Preliminary Determination Issued: 12/16/2014 Department Decision Issued: 01/15/2015 Permit Final: 01/31/2015 AFS #: 111-0011

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to Phillips 66 Company - Billings Refinery (Phillips 66), pursuant to Sections 75-2-204, 211, 213, and 215 of the Montana Code Annotated (MCA), as amended, and the Administrative Rules of Montana (ARM) 17.8.740, *et seq*., and 17.8.801, *et seq*., as amended, for the following:

SECTION I: Permitted Facility

A. Plant Location

Phillips 66 operates a petroleum refinery located at 401 South 23rd Street, Billings, Montana, in the NW¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County. A complete list of the permitted equipment for Phillips 66 is contained in Section I.A of the Permit Analysis.

B. Refinery Operations

Philips 66 operates a petroleum refinery, with those operations covered under this MAQP. The refinery operations at the source were provided a separate Title V Operating Permit for purposes of facilitating Responsible Official responsibilities in line with management structure. For Prevention of Significant Determination (PSD) and Maximum Achievable Control Technology (MACT) permit review purposes, the Refinery Operations are considered the same source as the Transportation and Jupiter operations.

C. Transportation Department Operations

Phillips 66 has loading rack operations adjacent to the refinery operations that are covered under this MAQP. Portions of the source under the management of the Transportation Department were provided a separate Title V Operating Permit for purposes of facilitating Responsible Official responsibilities in line with management structure. For PSD and MACT permit review purposes, the Transportation Operations, Refinery Operations, and Sulfur Recovery Operations are considered one source.

D. Sulfur Recovery Operations - Jupiter Sulphur, LLC (Jupiter)

Jupiter is a sulfur recovery operation within the petroleum refinery area described above at 2201 7th Avenue South, Billings, Montana. This operation is a joint venture, of which Phillips 66 is a partner. The Phillips 66 refinery management is responsible for maintaining air permit compliance of the Jupiter sulfur recovery operations. The Jupiter sulfur recovery operations consist of three primary units: the Ammonium Thiosulfate (ATS) Plant, the Ammonium Sulfide Unit (ASD), and the Claus Sulfur and Tail Gas Treating Units (TGTUs). Total sulfur recovery capacity is approximately 295 long tons per day (LT/D) of sulfur, with a feed rate capacity from the Phillips 66 refinery operations of approximately 235 LT/D of sulfur. A complete list of the permitted equipment is contained in Section I.B of the Permit Analysis. The Jupiter operations are covered under this MAQP and are a part of the Refinery Operations Title V Operating Permit. For PSD and MACT permit review purposes, the Jupiter operations are considered part of the same source as the Transportation and Refinery Operations.

E. Current Permit Action

On September 16, 2014, the Montana Department of Environmental Quality (Department) received an application from Phillips 66 to propose physical and operational changes to process units and auxiliary facilities at the refinery in order to provide more optimized operations for a broader spectrum of crude oil slates. Changes are primarily related to certain crude distillation, hydrogen production and recovery, fuel gas amine treatment, wastewater treatment, and sulfur recovery equipment and operations. A detailed list of project affected equipment with description of changes proposed is listed in the permit analysis, and is contained in the permit application.

All changes requiring permit modification are located in Section II.J of this permit, entitled Vacuum Improvement Project. Phillips 66 may request, or the Department may take action as needed, to administratively amend the permit as installation and startup of the relevant equipment has been accomplished, to clarify currently applicable conditions, and/or to reorganize permit requirements. All requirements of this section are to be applicable upon startup of the physical modification or change in operation of each unit.

SECTION II: Conditions and Limitations

A. Applicable Requirements

1. Phillips 66 shall comply with all applicable requirements of ARM 17.8.340, which reference 40 Code of Federal Regulations (CFR) Part 60, Standards of Performance for New Stationary Sources (NSPS):

    a. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS Subpart as listed below

    b. Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units shall apply to all affected boilers at the facility which were constructed after June 19, 1984, are larger than 100 million British thermal units per hour (MMBtu/hr), and combust fossil fuel. Phillips 66 shall comply with all applicable requirements of Subpart Db, for all affected boilers at the facility.

c. Subpart J - Standards of Performance for Petroleum Refineries shall apply to, but not be limited to:

i. All of the heaters and boilers at the Phillips 66 refinery (ARM 17.8.749);

ii. The Claus units at the Jupiter sulfur recovery;

iii. The Refinery Main Plant Relief Flare. Compliance will be in accordance with 40 CFR 60.11(d) in lieu of the requirements of 40 CFR 60.104, 105 and 107 (ARM 17.8.749);

iv. The Jupiter plant flare (Jupiter Flare, also known as the SRU/Ammonium Sulfide Unit Flare) ARM 17.8.749);

v. The Fluid Catalytic Cracking Unit (FCCU) (CO, SO_2, PM, and opacity provisions) (ARM 17.8.749); and

vi. Any other affected equipment.

d. Subpart Ja – Standards of Performance for Petroleum Refineries for which Construction, Reconstruction, or Modification commenced after May 14, 2007, shall apply to, but not be limited to:

i. The Delayed Coking Unit (Delayed Coker)

ii. Refinery Main Plant Releif Flare

iii. Jupiter Flare

iv. Any other affected equipment.

e. Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids shall apply to all petroleum storage vessels for which construction, reconstruction or modification commenced after May 18, 1978, and prior to July 23, 1984, for requirements not overridden by 40 CFR 63, Subpart CC. These requirements shall be as specified in 40 CFR 60.110a through 60.115a. The affected tanks include, but are not limited to, the following:

<u>Tank ID</u>
i. T-100*
ii. T-101*
iii. T-102
iv. T-104*
* *Currently exempt from all emission control provisions due to vapor pressure of materials stored.*

f. Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984, for requirements not overridden by 40 CFR 63, Subpart CC. These requirements shall be as specified in 40 CFR 60.110b through 60.117b. The affected tanks include, but are not limited to, the following:

Tank ID

i. T-35
ii. T-36 (Currently out of service)
iii. T-72
iv. T-107*
v. T-110
vi. T-0851 (No.5 HDS Feed Storage Tank)
vii. T-1102 (Crude Oil Storage Tank)
viii. T-2909 (LSG Tank)
ix. T-3201* (Currently out of service)

* *Currently exempt from all emission control provisions due to vapor pressure of materials stored.*

g. Subpart UU - Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture shall apply to, but not be limited to, asphalt storage tank T-3201 and any other applicable storage tanks that commenced construction or modification after May 26, 1981. Asphalt storage tank T-3201 shall comply with the standards in 40 CFR 60.472(c).

h. Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries shall apply to the following compressors:

i. C-3901, Coker Unit Wet Gas Compressor

ii. C-5301, Flare Gas Recovery Unit Liquid Ring Compressor

iii. C-5302, Flare Gas Recovery Unit Liquid Ring Compressor

iv. C-8301, Cryo Unit Inlet Gas Compressor

v. C-8302, Cryo Unit Refrigerant Compressor

vi. C-8303, Cryo Unit Regeneration Gas Compressor

i. Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries shall apply to the following compressors, which are in hydrogen service:

i. C-8401, No. 4 HDS Makeup/Recycle Hydrogen Compressor

ii. C-7401, Hydrogen Makeup/Reformer Hydrogen Compressor

iii. C-9401, Hydrogen Plant Feed Gas Compressor

iv. C-9501 Makeup/Recycle Gas Compressor

v. C-9701, Feed Gas Compressor

j. Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries shall apply to the C-8402, No. 4 HDS Makeup/Recycle Compressor, which is in hydrogen service.

k. Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 shall apply to, but not be limited to the group of all equipment (as defined in 40 CFR 60.591a) in the following process units:

i. Delayed coker unit

ii. Cryogenic unit

iii. Hydrogen membrane unit

iv. Gasoline merox unit

v. Crude vacuum unit

vi. Gas oil hydrotreater unit (consisting of a reaction section, fractionation section, and an amine treating section)

vii. No.1 H_2 Unit (22.0-million standard cubic feet per day (MMscfd) hydrogen plant feed system)

viii. Alkylation Unit Butane Defluorinator Project (consisting of heat exchangers; X-453, X-223, X-450, X-451, X-452, pumps; P-646, Vessels; D-130, D-359, D-360)

ix. Alkylation Unit Depropanizer Project

x. #3 Sour Water Stripper (SWS) Unit

xi. Fugitive components associated with boilers #B-5 and #B-6

xii. The fugitive components associated with the No.2 H_2 Unit and the No.5 HDS Unit

xiii. HPU and

xiv. Any other applicable equipment constructed or modified after November 7, 2006

l. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems, shall apply to, but not be limited to:

i. Coker unit drain system

ii. Desalter wastewater break tanks

iii. Corrugated Plate Interceptor (CPI) separators

iv. Gas oil hydrotreater oily water sewer drain system

v. No. 1 H_2 Unit (22.0-MMscfd hydrogen plant)

vi. C-23 compressor station oily water sewer drain system

vii. Alkylation Unit Butane Defluorinator oily water sewer drain system

viii. Alkylation Unit Depropanizer oily water sewer drain system

ix. #3 SWS Unit oily water sewer drain system

x. South Tank Farm oily water sewer drain system

xi. Tank T-4523 (wastewater surge tank)

xii. No. 2 H_2 Unit and the No.5 HDS Unit new individual oily water drain system, and

Any other applicable equipment, for requirements not overridden by 40 CFR 63, Subpart CC

m. Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines shall apply to, but not be limited to diesel-fired engine used for operation of the Backup Coke Crusher.

2. Phillips 66 shall comply with all applicable requirements of ARM 17.8.341, which references 40 CFR Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAP):

a. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP subpart as listed below.

b. Subpart FF - National Emission Standards for Benzene Waste Operations shall apply to, but not be limited to, all new or recommissioned wastewater sewer drains associated with the Alkylation Unit Depropanizer Project, the Refinery's existing sewer system, the #3 SWS Unit, the new individual drain system for the waste streams associated with the No.2 H_2 Unit and the No.5 HDS Unit, and Tanks 34 and 35.

c. Subpart M - National Emission Standard for Asbestos shall apply to, but not be limited to, the demolition and/or renovation of regulated asbestos containing material.

3. Phillips 66 shall comply with all applicable requirements of ARM 17.8.342, which reference 40 CFR Part 63, NESHAP for Source Categories, including the reporting, recordkeeping, testing, and notification requirements:

   a. Subpart A, General Provisions, applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

   b. Subpart R, National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), shall apply to, but not be limited to, the bulk loading rack.

   c. Subpart CC, National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries (Refinery MACT I), shall apply to, but not be limited to, Miscellaneous Process Vents; Storage Vessels; Wastewater Streams; and Equipment Leaks.

   d. Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (Refinery MACT II), shall apply to, but not be limited to, the FCCU and Catalytic Reforming Unit #2. Subpart UUU does not apply to the Catalytic Reforming Unit #1 as long as the reformer is dormant or the catalyst is regenerated off-site.

   e. Subpart EEEE, National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline) shall apply to, but not be limited to, Proto Gas storage tanks.

   f. Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines shall apply to, but not be limited to the diesel-fired engine used for operation of the Backup Coke Crusher, the Cryo Backup Air Compressor engine, the Boiler House Air Compressor engine, the Pump for Storm Water to Holding Pond engine, and the Boiler House Backup Air Compressor engine.

4. Phillips 66 shall comply with the provisions of 40 CFR 82, Subpart F, Recycling and Emission Reduction as applicable (ARM 17.8.749).

B. Emission Control Requirements

Phillips 66 shall install, operate, and maintain the following emission control equipment to provide the maximum air pollution control for which it was designed:

1. The Refinery Main Plant Relief flare must be equipped and operated with a steam injection system (ARM 17.8.752). The flare tip is to be based at a minimum of 142-feet plus or minus 2 feet elevation (ARM 17.8.749). Phillips 66 shall minimize SO_2 flaring activity by installing and operating flare gas recovery systems on the Refinery Main Plant Relief flare (ARM 17.8.749).

2. The Jupiter flare must be equipped and operated with a steam injection system (ARM 17.8.752). The flare tip is to be based at a minimum of 213-feet plus or minus 3 feet elevation (ARM 17.8.749).

3. Storage tank #49 shall be equipped with an internal floating roof with a double rim seal, liquid-mounted seal, or mechanical shoe seal system for VOC loss control (ARM 17.8.752).

4. Storage tanks #4510 and #4511 shall be equipped with internal floating roofs with double rim seals or a liquid-mounted seal system for VOC loss control (ARM 17.8.752).

5. The delayed coking unit drums shall depressure to 5 pounds per square inch gauge (psig) or less during reactor vessel depressuring (ARM 17.8.340, 40 CFR 60.103a(c)).

6. All compressors in Volatile Organic Compound (VOC) service (as defined in 40 CFR 60.591) subject to 40 CFR 60, Subpart GGG shall institute a compliance program as described under NSPS (40 CFR 60, Subpart VV, at 40 CFR 60.482 to 40 CFR 60.483 (ARM 17.8.340 and 40 CFR 60, Subpart GGG):

7. The C-23 Compressor station shall have a VOC monitoring and maintenance program instituted as described in 40 CFR 60.482-2, 40 CFR 60.482-4 thru 10, 40 CFR 60.483-1 and 2, 40 CFR 60.485, 40 CFR 60.486 (b-k), and 40 CFR 60.486 (c-e). If monitoring or scheduled inspections indicate failure or leakage of the compressor seal system, then the seals shall be repaired as soon as practicable (but not later than 15 calendar days after it is detected), except as provided in 40 CFR 60.482-9 (ARM 17.8.752).

8. All equipment (as defined in 40 CFR 60.591a) subject to 40 CFR 60, Subpart GGGa shall comply with the following (ARM 17.8.340 and 40 CFR 60 Subpart GGGa):

   a. All valves used shall be high-quality valves containing high-quality packing.

   b. All open-ended valves shall be of the same quality as the valves described above. They will have plugs, caps or a second valve installed on the open end.

   c. All pipe and tower flanges shall be installed using process compatible gasket material.

   d. All pumps shall be fitted with the highest quality state-of-the-art mechanical seals, as appropriate.

e. A monitoring and maintenance program as described under NSPS (40 CFR 60, Subpart VVa) shall be instituted.

9. All equipment subject to 40 CFR 60, Subpart QQQ shall comply with all applicable requirements, including (ARM 17.8.340 and 40 CFR 60, Subpart QQQ):

   a. All process drains shall consist of tightly sealed caps or P-leg traps for sewer drains with intermittent flow.

   b. The secondary oil/water separator is an oil/water (CPI) separator with hydrocarbon collection and recovery equipment.

   c. All equipment is operated and maintained as required by 40 CFR 60, Subpart QQQ.

10. All systems within the Phillips 66 refinery and Jupiter sulfur recovery operations (modifications) shall be totally enclosed and controlled such that any pollutant generated does not vent to atmosphere, except as expressly allowed in this permit (ARM 17.8.749).

11. Phillips 66 shall install and maintain the following burners:

   a. The recycle hydrogen heater (H-8401) and fractionator feed heater (H-8402) shall be equipped with Ultra Low NO_x Burner (ULNB) (ARM 17.8.752).

   b. The No.1 H_2 Plant Reformer Heater (H-9401) and the No. 2 H_2 Plant Reformer Heater (H-9701) shall be equipped with ULNBs (ARM 17.8.752 and ARM 17.8.819).

   c. The Claus SRU Incinerator (F-304) shall be equipped with LNB (ARM 17.8.752 and ARM 17.8.819).

   d. The coker heater (H-3901) shall be equipped with LNB.[1]

   e. Boilers #B-5 and #B-6 shall be equipped with ULNB (ARM 17.8.819).

   f. No.5 HDS Charge Heater and No.5 HDS Stabilizer Reboiler Heater (EPN-41 and 42, respectively) shall be equipped with ULNB (ARM 17.8.819).

12. Phillips 66 shall operate and maintain two CPI separator tanks with either carbon canister total VOC controls or a closed vent system routed to the wastewater treatment thermal oxidizer to comply with 40 CFR 60, Subpart QQQ, and 40 CFR 61, Subpart FF regulations. The CPI separators shall be vented to two carbon canisters in series, with no detectable emissions from

[1] The low NO_X burners for the coker heater are a requirement of the coker Permit #2619 issued April 19, 1990.

the connections and components in the closed vent system and canisters (ARM 17.8.340, ARM 17.8.341, 40 CFR 60 Subpart QQQ, 40 CFR 61, Subpart FF).

13. The bulk loading gasoline and distillates loading rack shall be operated and maintained as follows:

   a. Phillips 66's loading rack shall be equipped with a vapor collection system designed to collect the organic compound vapors displaced from cargo tanks during product loading (ARM 17.8.342 and 40 CFR 63, Subpart R).

   b. Phillips 66's collected vapors shall be routed to the Vapor Combustor Unit (VCU) at all times. In the event the VCU was inoperable, Phillips 66 may continue to load only distillates with a Reid vapor pressure of less than 27.6 kilopascals, provided the Department is notified in accordance with the requirements of ARM 17.8.110 (ARM 17.8.752).

   c. The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the gasoline cargo tank from exceeding 4,500 Pascals (Pa) (450 millimeters (mm) of water) during product loading. This level shall not be exceeded when measured by the procedures specified in the test methods and procedures in 40 CFR 60.503(d) (ARM 17.8.342 and 40 CFR 63, Subpart R).

   d. No pressure vacuum vent in the permitted terminal's vapor collection system shall begin to open at a system pressure less than 4,500 Pa (450 mm of water) (ARM 17.8.342 and 40 CFR 63, Subpart R).

   e. The vapor collection system shall be designed to prevent VOC vapors collected at one loading position from passing to another loading position (ARM 17.8.342 and 40 CFR 63, Subpart R).

   f. Loading of liquid products into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks using the following procedures (ARM 17.8.342 and 40 CFR 63, Subpart R):

      i. Phillips 66 shall obtain annual vapor tightness documentation described in the test methods and procedures in 40 CFR 63.425(e) for each gasoline cargo tank that is to be loaded at the loading rack.

      ii. Phillips 66 shall require the cargo tank identification number to be recorded as each gasoline cargo tank is loaded at the terminal.

      iii. Phillips 66 shall cross check each tank identification number obtained during product loading with the file of tank vapor tightness documentation within 2 weeks after the corresponding cargo tank is loaded.

iv. Phillips 66 shall notify the owner or operator of each non-vapor-tight cargo tank loaded at the loading rack within 3 weeks after the loading has occurred.

v. Phillips 66 shall take the necessary steps to ensure that any non-vapor-tight cargo tank will not be reloaded at the loading rack until vapor tightness documentation for that cargo tank is obtained which documents that:

a. The gasoline cargo tank meets the applicable test requirements in 40 CFR 63.425(e) of this permit.

b. For each gasoline cargo tank failing the test requirements in 40 CFR 63.425(f) or (g), the gasoline cargo tank must either:

i. Before the repair work is performed on the cargo tank, meet the test requirements in 40 CFR 63.425 (g) or (h).

ii. After repair work is performed on the cargo tank before or during the tests in 40 CFR 63.425 (g) or (h), subsequently passes, the annual certification test described in 40 CFR 63.425(e).

g. Phillips 66 shall ensure that gasoline cargo tanks at the loading rack are loaded only into cargo tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system (ARM 17.8.342 and 40 CFR 63, Subpart R).

h. Phillips 66 shall ensure that the terminal and the cargo tank vapor recovery systems are connected during each loading of a gasoline cargo tank at the loading rack (ARM 17.8.342 and 40 CFR 63, Subpart R).

i. Loading of cargo tanks shall be restricted to the use of submerged fill and dedicated normal service (ARM 17.8.749).

j. Phillips 66 shall install and continuously operate a thermocouple and an associated recorder for temperature monitoring in the firebox or ductwork immediately downstream in a position before any substantial heat occurs, and develop an operating parameter value for the VCU in accordance with the provisions of 40 CFR 63.425 and 63.427 (ARM 17.8.342 and 40 CFR 63, Subpart R; and ARM 17.8.752).

k. Phillips 66 shall perform a monthly leak inspection of all equipment in gasoline service. The inspection must include, but is not limited to, all valves, flanges, pump seals, and open-ended lines. For purposes of this inspection, detection methods incorporating sight, sound, or smell are acceptable. Each piece of equipment shall be inspected during the loading of a gasoline cargo tank (ARM 17.8.342 and 40 CFR 63, Subpart R).

l. A logbook shall be used and shall be signed by the owner or operator at the completion of each inspection. A section of the log shall contain a list, summary description, or diagram(s) showing the location of all equipment in gasoline service at the facility (ARM 17.8.342 and 40 CFR 63, Subpart R).

m. Each detection of a liquid or vapor leak shall be recorded in the logbook. When a leak is detected, an initial attempt at repair shall be made as soon as practicable, but no later than 5 calendar days after the leak is detected. Repair or replacement of leaking equipment shall be completed within 15 calendar days after detection of each leak, except as provided in "n" below (ARM 17.8.342 and 40 CFR 63, Subpart R).

n. Delay of repair of leaking equipment will be allowed upon a demonstration to the Department that repairs within 15 days are not feasible. The owner or operator shall provide the reason(s) a delay is needed and the date by which each repair is expected to be completed (ARM 17.8.342 and 40 CFR 63, Subpart R).

o. Phillips 66 shall not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:

i. Minimize gasoline spills;

ii. Clean up spills as expeditiously as practicable;

iii. Cover all open gasoline containers with a gasketed seal when not in use and;

iv. Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators (ARM 17.8.342 and 40 CFR 63, Subpart R).

14. Jupiter shall vent off-gas from the ASD unit operation to the B304 sulfur boiler except during malfunction or maintenance conditions, when the off-gases would be vented to the Jupiter SRU flare (ARM 17.8.749).

15. Phillips 66 shall operate a temporary natural gas-fired boiler for up to 8 weeks per rolling 12-month period. The temporary boiler will not exceed a firing rate of 51 MMBtu/hr, and will only be used during refinery turnarounds (ARM 17.8.749).

16. Phillips 66 shall operate and maintain an amine-based chemical absorption system on the refinery fuel gas system (ARM 17.8.752 and ARM 17.8.819).

17. The Claus SRU shall be equipped with a TGTU (ARM 17.8.752 and ARM 17.8.819).

C. Emission Limitations

1. Total refinery and sulfur recovery facility emissions shall not exceed the following (ARM 17.8.749, unless otherwise noted):

a. Jupiter SRU/ATS Main Stack (S-101/S-401)

i. SO_2 Emissions –

(A) 25.00 pounds per hour (lbs/hr) (ARM 17.8.749)

(B) 167 ppmv, corrected to 0% O2 on a dry basis, on a rolling 12- hour average

(C) 0.30 tons/day

ii. NO_X Emissions - 18.92 lbs/hr, 454.0 lbs/day, 82.85 TPY

iii. PM10 Emissions – 7.76 lbs/hr, 186.3 pounds per day (lb/day), 34.00 TPY

iv. CO Emissions - 0.40 lb/hr, 1.76 TPY

v. Ammonia - 13.36 lbs/hr, 320.5 lb/day, 58.5 TPY

vi. Opacity - 20% averaged over any 6 consecutive minutes.

b. Jupiter SRU Flare[2]

i. SO_2 Emissions - 25.00 lbs/hr, 0.30 tons/day.

ii. Hydrogen Sulfide (H_2S) content of the flare fuel gas (and pilot gas) burned shall not exceed 0.10 grain/dry standard cubic foot (gr/dscf) (ARM 17.8.749), with the exception of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions (ARM 17.8.340, 40 CFR 60, Subpart J, and 40 CFR 60, Subpart Ja).

iii. PM and CO emissions shall be kept to their negligible levels as indicated in the permit application.

iv. Opacity - 20% averaged over any 6 consecutive minutes.

[2] Emissions occur only during times that the ATS plant is not operating.

c. Total SO_2 emissions from the Jupiter SRU/ATS main stack plus the Jupiter SRU flare shall not exceed 109.5 TPY (rolling 12-month average).

d. FCCU Stack

i. SO_2 Emissions shall not exceed 328.8 lbs/hr, rolling 24-hour average; 3.945 ton/day; 48.86 TPY.

ii. SO_2 emissions from the FCCU shall not exceed 25 ppmvd at 0% O_2 based on a rolling 365-day average, as well as 50 ppmvd at 0% O_2 based on a rolling 7-day average. The 7-day SO_2 emission limit shall not apply during periods of hydrotreater outages at the Billings Refinery or during startup, shutdown or malfunction of the FCCU, or during periods of malfunction of a control system or pollutant-reducing catalyst additive system, provided that Phillips 66 is maintaining and operating its FCCU (including associated air pollution control equipment) in a manner consistent with good air pollution control practices for minimizing emissions (ARM 17.8.749).

iii. SO_2 Emissions from FCCU shall not exceed 9.8 kilograms per Megagram (kg/Mg, or 20 lb/ton) coke burnoff on a 7-day rolling average basis, in accordance with 40 CFR 60.104(b)(2) and (c). As an alternative, Phillips 66 shall process in the FCCU fresh feed that has a total sulfur content no greater than 0.30 percent by weight on a 7-day rolling average basis, in accordance with 40 CFR 60.104(b)(3) and (c). This limit became effective on February 1, 2005 (40 CFR 60 Subpart J and ARM 17.8.749).

iv. CO Emissions shall not exceed 150 ppmvd at 0% O_2 based on a rolling 365-day average basis (ARM 17.8.749)

v. CO Emissions shall not exceed 500 ppmvd at 0% O_2 based on a one-hour average emission limit. CO emissions during periods of startup, shutdown or malfunctions of the FCCU will not be used for determining compliance with this emission limit, provided that Phillips 66 implements good air pollution control practices to minimize CO emissions (ARM 17.8.749).

vi. CO Emissions shall not exceed 500 ppmvd based on a one-hour average (40 CFR 60 Subpart J and ARM 17.8.749)

vii. NO_x emissions shall not exceed 49.2 ppmvd corrected to 0% O_2, on a rolling 365-day average and 69.5 ppmvd, corrected to 0% O_2, on a rolling 7-day average. The 7-day NO_x emission limit shall not apply during periods of hydrotreater outages at the Billings Refinery or during startup, shutdown or malfunction of the FCCU, or during periods of malfunction of a control system or pollutant-reducing catalyst additive system, provided that Phillips 66 is maintaining and operating the FCCU (including associated air pollution control equipment) in a manner consistent with good air pollution control practices for minimizing emissions in accordance with the EPA-approved good air pollution control practices plan. For days in which the FCCU is not operating, no NOx value shall be used in the average, and those periods shall be skipped in determining the 7-day and 365-day averages (ARM 17.8.749).

viii. PM Emissions - The FCCU shall not exceed the PM limit of 1 lb/1000 lbs coke burned (40 CFR 60, Subpart J and ARM 17.8.749).

ix. Opacity – not to exceed 30%, except for one 6-minute average in any 1 hour period (40 CFR 60 Subpart J and ARM 17.8.749).

e. <u>Refinery Fuel Gas Heaters/Furnaces</u>

i. Phillips 66 shall not burn fuel oil in any of its heaters (ARM 17.8.749).

ii. Combined SO_2 Emissions shall not exceed: 614 lb/day, rolling 24-hour average; and 45.5 TPY, rolling 12-month average for the following fuel gas combustion units:

(A) Emission Point 2, H-1;
(B) Emission Point 3, H-2;
(C) Emission Point 4, H-4;
(D) Emission Point 5, H-5;
(E) Emission Point 7, H-10 – No. 2 HDS;
(F) Emission Point 8, H-11 – No. 2 HDS Debutanizer Reboiler;
(G) Emission Point 9, H-12 – No. 2 HDS Main Frac. Reboiler;
(H) Emission Point 10, H-13 – Catalytic Reforming Unit #2;
(I) Emission Point 11, H-14 – Catalytic Reforming Unit #2;
(J) Emission Point 12, H-15;
(K) Emission Point 13, H-16 – Saturated Gas Stabilizer Reboilern and PB Merox Disulfide Offgas;
(L) Emission Point 14, H-17;
(M) Emission Point 15, H-18;
(N) Emission Point 16, H-19;
(O) Emission Point 17, H-20;

(P) Emission Point 18, H-21;
(Q) Emission Point 20, H-23 – Catalytic Reforming Unit #2;
(R) Emission Point 21, H-24;
(S) Emission Point 6, H-3901 – Coker Heater;
(T) Emission Point 28, H-8401 – Recycle Hydrogen Heater; (U) Emission Point 29, H-8402 – Fractionator Feed Heater.

iii. H_2S content of fuel gas burned shall not exceed 0.10 gr/dscf, rolling 3-hr average (ARM 17.8.749).

iv. H_2S content of fuel gas shall not exceed 0.073 gr/dscf (116.5 ppmv H_2S) per rolling 12-month time period, for fuel gas burned in (ARM 17.8.749):

(A) Emission point 35, H-9401, the No. 1 H_2 Reformer Heater
(B) Emission point 7, H-10, the No. 2 HDS
(C) Emission point 8, H-11, the Debutanizer Reboiler, No. 2 HDS
(D) Emission point 9, H-12, the Main Frac. Reboiler No. 2 HDS
(E) Emission point 10, H-13, Catalytic Reforming Unit #2
(F) Emission point 11, H-14, Catalytic Reforming Unit #2
(G) Emission point 13, H-16, the Stabilizer Reboiler, Sat Gas
(H) Emission point 20, H-23, Catalytic Reforming Unit #2
(I) Emission point 41, No.5 HDS Charge Heater
(J) Emission point 42, No.5 HDS Stabilizer Reboiler Heater
(K) Emission point 43, No. 2 H_2 Reformer Heater

v. Opacity from each of the Refinery Fuel Gas Heaters/Furnaces constructed prior to 1968 shall not exceed 40% averaged over any 6 consecutive minutes (ARM 17.8.304).

vi. Opacity from each of the Refinery Fuel Gas Heaters/Furnaces constructed after 1968, including the No.5 HDS Charge Heater, No.5 HDS Stabilizer Reboiler Heater, No.2 H_2 Plant Reformer Heater (H-9701), Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, No. 1 H_2 Plant Reformer Heater (H-9401), and H-1 shall each not exceed 20% averaged over 6 consecutive minutes (ARM 17.8.304).

vii. NO_X emissions from the No.5 HDS Charge Heater shall not exceed 0.03 pound per million British thermal units (lb/MMBtu) per rolling 12-month time period (ARM 17.8.752).

viii. CO emissions from the No.5 HDS Charge Heater shall not exceed 0.317 lb/MMBtu per rolling 12-month time period when the heater is operating at 10.9 MMBtu/hr or less (ARM 17.8.752).

ix. CO emissions from the No.5 HDS Charge Heater shall not exceed 0.1585 lb/MMBtu per rolling 12-month time period when the heater is operating at greater than 10.9 MMBtu/hr (ARM 17.8.752).

x. NO_X emissions from the No.5 HDS Stabilizer Reboiler Heater shall not exceed 0.03 lb/MMBtu per rolling 12-month time period (ARM 17.8.752).

xi. CO emissions from the No.5 HDS Stabilizer Reboiler Heater shall not exceed 0.1585 lb/MMBtu per rolling 12-month time period when the heater is operating at 29.9 MMBtu/hr or less (ARM 17.8.752).

xii. CO emissions from the No.5 HDS Stabilizer Reboiler Heater shall not exceed 0.091 lb/MMBtu per rolling 12-month time period when the heater is operating at greater than 29.9 MMBtu/hr (ARM 17.8.752).

xiii. The PSA purge gas used as heater fuel in the No. 2 H_2 Plant Reformer Heater (H-9701) shall be sulfur free (ARM 17.8.752).

xiv. The total NO_X emissions from the No.5 HDS Charge Heater (H-9501), the No.5 HDS Stabilizer Reboiler Heater (H-9502), and the No.2 H_2 Plant Reformer Heater (H-9701) shall not exceed 7.95 lbs/hr and 34.19 TPY (ARM 17.8.752).

xv. NO_X emissions from the No. 1 H_2 Plant Reformer Heater (H-9401) and the No.2 H_2 Plant Reformer Heater (H-9701) shall not exceed 0.03 lb/MMBtu per rolling 12-month time period (ARM 17.8.752 and ARM 17.8.819).

xvi. CO emissions from the No. 1 H_2 Plant Reformer Heater (H-9401) and the No. 2 H_2 Plant Reformer Heater (H-9701) shall not exceed 0.025 lb/MMBtu per rolling 12-month time period. The PSA purge gas used as heater fuel shall be sulfur free (ARM 17.8.752).

xvii. NO_X emissions from the Coker Heater (H-3901) shall not exceed 0.08 lb/MMBtu and 7.38 lbs/hr (ARM 17.8.752).

xviii. NO_X emissions from the Recycle Hydrogen Heater (H-8401) shall not exceed 0.03 lb/MMBtu (ARM 17.8.752).

xix. NO_X emissions from the Fractionator Feed Heater (H-8402) shall not exceed 0.03 lb/MMBtu (ARM 17.8.752).

xx. The total NO_X emissions from the Coker Heater (H-3901), Recycle Hydrogen Heater (H-8401), Fractionator Feed Heater (H-8402), and the No. 1 H2 Plant Reformer Heater (H-9401) shall not exceed 13.54 lbs/hr and 58.95 TPY (ARM 17.8.752).

xxi. PM_{10} and $PM_{2.5}$ emissions from the No. 1 H_2 Plant Reformer Heater (H-9401) and No. 2 H_2 Plant Reformer Heater (H-9701) shall not exceed 0.0075 lb/MMBtu per rolling 12-month time period (ARM 17.8.752 and ARM 17.8.819).

f. <u>Main Boilerhouse Stack</u>

i. SO_2 Emissions - 321.4 lbs/hr, rolling 24-hour average; 3.857 ton/day; 1,407.8 TPY (fuel oil and fuel gas combustion).

ii. SO_2 Emissions – 300 TPY from fuel oil combustion, based on a rolling 365-day average as determined by the existing SO_2 Continuous Emissions Monitoring System (CEMS) or replacement SO_2 CEMS subsequently installed and certified (ARM 17.8.749).

iii. H_2S content of fuel gas burned shall not exceed 0.10 gr/dscf, rolling 3-hr average.

iv. H_2S content of fuel gas burned in boilers #B-5 and #B-6 shall not exceed 96 ppmv on a rolling 365-day average (ARM 17.8.749).

v. Opacity - 40% averaged over any 6 consecutive minutes, except during times that the exhaust from only boilers #B-5 and #B-6 are being routed to the main boiler stack, the opacity limit is 20% (ARM 17.8.340).

vi. NO_X emissions from boilers #B-5 and #B-6 shall each, when fired on RFG, not exceed 0.03 lb/MMBtu based on a rolling 365-day average or 24.05 TPY based on a rolling 365-day average. Compliance with the limits shall be monitored with the NO_X and O_2 CEMS subsequently installed and certified (ARM 17.8.752).

vii. CO emissions from boilers #B-5 and #B-6 shall each not exceed 0.04 lb/MMBtu based on a rolling 365-day average fired on RFG (ARM 17.8.752).

viii. VOC Emissions from boilers #B-5 and #B-6 shall each not exceed 4.32 tons/rolling 12-calendar month total (ARM 17.8.752).

g. PMA Storage Tank Vent (T-3201)

Opacity shall not exceed 0%, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown clear (40 CFR 60.472(c)).

h. Total SO_2 emissions for refinery and sulfur recovery facilities

Total SO_2 emissions for refinery and sulfur recovery facilities shall not exceed the limit of 3,103 TPY. In addition, where applicable, all other federal emission limitations shall be met. (ARM 17.8.749)

2. All access roads shall use either paving or chemical dust suppression as appropriate to limit excessive fugitive dust, with water as a back-up measure, to maintain compliance with ARM 17.8.308 and the 20% opacity limitation. Phillips 66 shall use reasonable precautions during construction, and earth-moving activities shall use reasonable precautions to limit excessive fugitive dust and to mitigate impacts to nearby residential and commercial places (ARM 17.8.308).

3. Emissions from the loading of gasoline and distillates at the loading rack shall be limited to the following:

a. The total VOC emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 milligrams per liter (mg/L) of gasoline loaded (ARM 17.8.342; 40 CFR 63, Subpart R; and ARM 17.8.752).

b. The total CO emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 mg/L of gasoline loaded (ARM 17.8.752).

c. The total NO_X emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 4.0 mg/L of gasoline loaded (ARM 17.8.752).

d. Phillips 66 shall not cause or authorize to be discharged into the atmosphere from the enclosed VCU:

i. Any visible emissions that exhibit an opacity of 10% or greater (ARM 17.8.749)

ii. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% CO_2 (ARM 17.8.749)

4. Phillips 66 shall operate and maintain the Saturate Gas Plant according to the Leak Detection and Repair (LDAR) program. Phillips 66 shall monitor and maintain all pumps, shutoff valves, relief valves, and other piping and valves associated with the Saturate Gas Plant, as described in 40 CFR 60.482-1 through 60.482-10. Records of monitoring and maintenance shall be maintained on site for a minimum of 5 years (ARM 17.8.342, 40 CFR 63, Subpart CC and ARM 17.8.752).

5. Phillips 66 shall operate and maintain all new (associated with the Low Sulfur Gasoline (LSG) project) fugitive component VOC emissions in the No.2 HDS Unit, the Gas Oil Hydrodesulfurizer (GOHDS) Unit, and the Tank Farm (including those fugitive emissions associated with the LSG tank) according to the LDAR program (ARM 17.8.342; 40 CFR 63, Subpart CC; and ARM 17.8.752).

6. <u>Refinery Main Plant Relief Flare Stack</u>

   a. Phillips 66 shall meet the 40 CFR 60, Subpart A & J requirements by installing and operating a flare gas recovery system (FGRS), as a means of implementing good air pollution control practices in accordance with 40 CFR 60.11(d) in lieu of meeting the emission limits and monitoring and recordkeeping requirements of 40 CFR 60.104, 105, and 107. Phillips 66 shall operate the FGRS at all times that the facility is operating, except during any reasonably required maintenance on the flare system and/or the FGRS, or during periods of maintenance that would result in the frequent starting-up and shutting-down for the FGRS; the FGRS is shutdown for safety reasons; or it cannot effectively be operated due to the shutdown or operational problems associated with one or more units (ARM 17.8.749).

   b. For any acid gas, hydrocarbon, or tail gas flaring incident that results in emission of SO_2 that are equal or greater than 500 lbs in a 24-hour period, Phillips 66 shall prepare a Root Cause Failure Analysis (RCFA) and corrective action (ARM 17.8.749).

   c. SO_2 emission increases, due to upset conditions or discontinuance of the SRU, shall be offset by an equivalent rate from any other sources covered by this permit (ARM 17.8.749).

7. <u>Jupiter Flare</u>

   a. Phillips 66 shall meet the 40 CFR 60, Subpart A & J requirements by operating the flare such that it only receives process upset gas, fuel gas that is released to the flare as a result of relief valve leakage, or other emergency malfunctions (as defined in 40 CFR 60, Subpart J) (ARM 17.8.749).

   b. Phillips 66 shall prepare a RCFA and corrective action for any flaring incident that results in emissions of SO_2 that are equal or greater than 500 lbs in a 24-hour period (ARM 17.8.749).

8. Backup Coke Crusher and Associated Diesel Fired Engine (CG3810)

   a. The Coke Crusher and the Backup Coke Crusher shall not be operated simultaneously (ARM 17.8.749).

   b. Engine associated with CG3810 shall not exceed a horsepower rating of 300 hp and shall have an EPA certification of Tier 3 or higher (ARM 17.8.749).

   c. Phillips 66 shall use only ultra-low-sulfur diesel fuel with a sulfur content less than or equal to 0.0015% in the engine associated with CG3810 (ARM 17.8.752).

D. Testing Requirements – NSPS, NESHAP, and MACT

1. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.

2. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart J, Standards of Performance for Petroleum Refineries.

3. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.

4. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart Ka, Standards of Performance for Storage Vessels for Petroleum Liquids. This shall apply to all petroleum liquid storage vessels for which construction, reconstruction or modification commenced after May 18, 1978, and prior to July 23, 1984 (for requirements not overridden by 40 CFR 63, Subpart CC). These requirements shall be as specified in 40 CFR 60.110a through 60.115a.

5. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels. This shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984 (for requirements not overridden by 40 CFR 63, Subpart CC).

6. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries.

7. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006

8. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart QQQ, Standards of Performance for Volatile Organic Compound Emissions from Petroleum Refinery Wastewater Systems (for requirements not overridden by 40 CFR 63, Subpart CC).

9. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63, Subpart R, NESHAPs for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations).

10. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63, Subpart CC, NESHAPs from Petroleum Refineries.

11. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63, Subpart UUU, NESHAPs for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

12. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63, Subpart EEEE, NESHAPs for Organic Liquids Distribution (Non-Gasoline).

E. Emission Testing and Monitoring

1. Phillips 66 shall test boilers #B-5 and #B-6 for NO_X and CO, both pollutants concurrently, and demonstrate compliance with the NO_X and CO emission limits contained in Sections II.C.1.f.vi and vii. The compliance source testing shall be conducted on an every 5-year basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and 17.8.749).

2. Phillips 66 shall conduct compliance source tests on the Jupiter SRU Main stack for PM_{10} and NO_X to determine compliance with the applicable emission standards in Section II.C.1.a in 1998, 2002, and every 5 years thereafter.

3. The bulk loading rack VCU shall be tested for total organic compounds, and compliance demonstrated with the emission limitation contained in Section II.C.3.a every 5 years. Phillips 66 shall conduct the test methods and procedures as specified in 40 CFR 63.425, Subpart R (ARM 17.8.105 and 17.8.342).

4. To demonstrate compliance with the PM limitations listed in Section II.C.1.d.vii, Phillips 66 shall conduct a PM stack test annually, unless another testing schedule is approved by the Department (ARM 17.8.749).

5. Phillips 66 shall install and operate the following CEMS/continuous emission rate monitors (CERMs):

   a. Jupiter SRU/ATS Stack

      i. SO_2 (SO_2 State Implementation Plan (SIP), 40 CFR 60, Subpart J)

      ii. O_2 (40 CFR 60, Subpart J)

      iii. Volumetric flow rate (SO_2 SIP)

   b. FCCU Stack

      i. SO_2 (40 CFR 60 Subpart J and ARM 17.8.749)

      ii. Volumetric flow rate (SO_2 SIP)

      iii. Opacity (40 CFR 60 Subpart J and ARM 17.8.749)

      iv. CO (40 CFR 60 Subpart J and ARM 17.8.749)

      v. NO_x (ARM 17.8.749)

      vi. O_2 (ARM 17.8.749)

   c. Main Boiler Stack

      i. SO_2 (SO_2 SIP; ARM 17.8.749)

      ii. Volumetric flow rate (SO_2 SIP)

   d. Boilers #B-5 and #B-6

      i. NO_X (40 CFR 60, Subpart Db)

      ii. O_2 (ARM 17.8.749)

   e. Boilers and RFG Heaters/Furnaces (ARM 17.8.749):

      Continuous H_2S RFG System Monitoring - Compliance with the limits of 40 CFR 60, Subpart J shall be determined by the H_2S CEMS on the fuel gas system that supplies the heaters and boilers (SO_2 SIP). Compliance with the limits listed in Sections II.C.1.e.v – vi and II.C.1.i.iii shall be determined by the H_2S CEMS on the fuel gas system that supplies the heaters and boilers). Continuous refinery fuel gas monitoring system for H_2S shall meet all performance specifications, methods and procedures. H_2S concentration monitor on the fuel gas system shall meet 40 CFR 60, Appendix B, Performance Specification 7.

f. Flare(s): (Refinery Main Plant Relief Flare, and Jupiter Flare) (ARM 17.8.749):

i. Phillips 66 shall maintain records of the extent and duration of all periods in which the FGRS for the Refinery Main Plant Relief Flare is not operated. During such periods, Phillips 66 shall also measure or estimate (as appropriate) all SO_2 emissions which result from gases being directed to and combusted in the flare.

ii. Flow rate metering from upset or malfunctioning process units that are directed to the flare shall use approved standards, methods, accounting procedures, and engineering data.

iii. Recordkeeping requirements (see Sections II.F.1-2)

6. Enforcement of Section II.C.1 and II.C.6 requirements, where applicable, shall be determined by utilizing data taken from CEMS and other Department-approved sampling methods. However, opacity compliance may also be determined via EPA Reference Method 9 by a certified observer or monitor (ARM 17.8.749).

a. The above does not relieve Phillips 66 from meeting any applicable requirements of 40 CFR 60, Appendices A and B, or other stack testing that may be required by the Department.

b. Other stack testing may include, but is not limited to, the following air pollutants: SO_2, NO_X, ammonia (NH_3), CO, PM, PM_{10}, and VOC.

c. Reporting requirements shall be consistent with 40 CFR Part 60, or as specified by the Department.

d. SO_2 SIP CEMS shall be required to be maintained such that they are available and operating at least 90% of the source operating time during any reporting period (quarterly).

7. Phillips 66 shall install, operate and maintain the applicable CEMS/CERMS listed in Sections II.E.5.a, b, and c. Emission monitoring shall be subject to 40 CFR 60, Subpart J, Appendix B (Performance Specifications 1, 2, 3, 4/4A/4B, and 6) and Appendix F (Quality Assurance/Quality Control) provisions (ARM 17.8.749).

8. Phillips 66 shall install, operate and maintain the applicable CEMS listed in Sections II.E.5.b.v. and vi. Emission monitoring shall be subject to 40 CFR 60, Appendix A, Appendix B (Performance Specifications 2 and 3 and Appendix F

(Quality Assurance/Quality Control) provisions (ARM 17.8.749). With respect to Appendix F, in lieu of the requirements of 40 CFR 60 Appendix F 5.1.1, 5.1.3 and 5.1.4, Phillips 66 shall conduct either a Relative Accuracy Audit or a Relative Accuracy Test Audit once every twelve (12) calendar quarters, provided that a Cylinder Gas Audit is conducted each calendar quarter.

9. Phillips 66 shall install, operate and maintain the applicable CEMS/CERMS listed in Section II.E.5.d. Emission monitoring shall be subject to 40 CFR 60, Subpart Db; Appendix B (Performance Specifications 2, 3, 4/4A/4B, and 6). Emission monitoring shall be subject to 40 CFR 60, Appendix F or an alternate site-specific monitoring plan approved by the Department, as appropriate (ARM 17.8.749).

10. Phillips 66 shall install, operate and maintain the applicable CEMS/CERMS listed in Sections II.E.5.f. Emission monitoring shall be subject to 40 CFR 60, Appendix B (Performance Specification 7) and Appendix F (Quality Assurance/Quality Control) provisions (the cylinder gas manufacturer's procedures for certifying these standards shall be considered adequate for Appendix F purposes) (ARM 17.8.749).

11. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, Phillips 66 shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated. The Department shall approve such contingency plans (ARM 17.8.749).

12. Compliance testing and continuous monitor certification shall be as specified in 40 CFR 60, Appendices A and B. Test methods and procedures, where there is more than one option for any given pollutant, shall be worked out with the Department prior to commencement of testing (ARM 17.8.749).

13. Phillips 66 shall conduct compliance testing and continuous monitor certification as specified in 40 CFR 60, Appendices A and B, within 180 days of initial start up of the affected facility (ARM 17.8.749).

14. Any stack testing requirements that may be required in Sections II.E.1 to II.E.6 and II.E.8 shall be conducted according to 40 CFR 60, Appendix A and ARM 17.8.105, Testing Requirements provisions. (ARM 17.8.749).

15. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

16. The Department may require further testing (ARM 17.8.105).

F. Reporting

1. Phillips 66 shall provide quarterly and/or semi-annual emission reports from all emission rate monitors. In addition to any specific NSPS or NESHAP reporting requirements, the periodic reports shall include the following (ARM 17.8.749):

   a. Quarterly emission reporting for SO_2 from all point source locations shall consist of 24-hour calendar-day totals per calendar month;

   b. Source or unit operating time during the reporting period;

   c. Monitoring down time, which occurred during the reporting period;

   d. A summary of excess emissions for each pollutant and averaging period identified in Section II.C; and

   e. Reasons for any emissions in excess of those specifically allowed in Section II.C. with mitigative measures utilized and corrective actions taken to prevent a recurrence of the upset situation.

   Phillips 66 shall submit the quarterly and/or semi-annual emission reports within 30 days of the end of each reporting period.

2. Phillips 66 shall keep the Department apprised of the status of construction, dates of performance tests, and continuous compliance status for each emission point and pollutant. Specifically, the following report and recordkeeping shall be submitted in writing (ARM 17.8.749):

   a. Notification of date of construction commencement, cessation of construction, restarts of construction, startups, initial emission tests, monitor certification tests, etc.

   b. Submittal for review by the Department of the emissions testing plan, results of initial compliance tests, continuous emission monitor certification tests, continuous emission monitoring and continuous emissions rate monitoring quality assurance/quality control plans, and excess emissions report within the 180-day shakedown period.

   c. Copies of emissions reports, excess emissions, and all other such items mentioned in Section II.F.2.a and b above shall be submitted to both the Billings Regional Office and the Helena office of the Department.

   d. Monitoring data shall be maintained for a minimum of 5 years at the Phillips 66 Refinery and Jupiter sulfur recovery facilities.

   e. All data and records that are required to be maintained must be made available upon request by representatives of the EPA.

3. Phillips 66 shall report to the Department any time in which the sour water stripper stream from the refinery is diverted away from the sulfur recovery facility. Said excess emission reports shall include the period of diversion, estimate of lost raw materials (H_2S and NH_3), and resultant pollutant emissions, including circumstances explaining the diversion of this stream. Said excess emission reports shall discuss what corrective actions will be taken to prevent recurrences of the situation and what caused the upset. These reports shall address, at a minimum, the requirements of ARM 17.8.110 (ARM 17.8.749).

4. Phillips 66 shall document, by month, the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No.2 H_2 Unit PSA Offgas Vent. By the 30th day of each month Phillips 66 shall total the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No.2 H_2 Unit PSA Offgas Vent during the previous month. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

5. Phillips 66 shall document, by month, the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No.1 H_2 Unit PSA Offgas Vent. By the 30th day of each month Phillips 66 shall total the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No.1 H_2 Unit PSA Offgas Vent during the previous month. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

6. Phillips 66 shall report quarterly, the daily NOx rolling 365-day average and the maximum NOx 7-day rolling average per quarter for the FCCU stack. These reports shall also include NOx CEMS quarterly performance (excess emissions and monitor downtime) and Appendix F (Quality Assurance and Quality Control) provisions. FCCU quarterly NOx reporting shall be submitted in conjunction with the SO_2 SIP emissions and CEMS/CERMS reporting periods (ARM 17.8.749).

7. Phillips 66 shall document, annually, the number of operational hours of the Backup Coke Crusher. The information shall be submitted along with the annual emission inventory required by Section II.H.1 (ARM 17.8.749),

8. Phillips 66 shall document, annually, the maximum sulfur content of the diesel fuel used by the engine associated with CG3810 for the previous calendar year. Vendor specifications or certification that the fuels met the maximum sulfur content allowed by the current motor fuel regulations (40 CFR Part 80) will satisfy this requirement. The annual information shall be used to verify compliance with the limitation in Section II.C.8.c. The information shall be submitted along with the annual emission inventory required by Section II.H.1 (ARM 17.8.749).

G. Additional Reporting Requirements - NSPS, NESHAP, and MACT:

1. Phillips 66 shall keep records and furnish reports to the Department as required by 40 CFR 60, NSPS, Subpart Kb, for requirements not overridden by 40 CFR 63, Subpart CC. These reports shall include information described in 40 CFR 60.115b (ARM 17.8.749).

2. Phillips 66 shall provide copies to the Department, upon the Department's request, of any records of tank testing results required by 40 CFR 60.113b and monitoring of operations required by 40 CFR 60.116b. Records will be available according to the time period requirements as described in 40 CFR 60.115b and 40 CFR 60.116b (ARM 17.8.749).

3. Phillips 66 shall keep records and furnish reports to the Department as required by 40 CFR 60, Subpart QQQ, for requirements not overridden by 40 CFR 63, Subpart CC (ARM 17.8.749).

4. Phillips 66 shall provide copies to the Department, upon the Department's request, of any records of testing results, monitoring operations, recordkeeping and report results as specified under 40 CFR 60, Subpart QQQ, Sections 60.693-2, 60.696, 60.697, and 60.698, for requirements not overridden by 40 CFR 63, Subpart CC (ARM 17.8.749).

5. Phillips 66 shall monitor the exhaust vent stream from the wastewater CPI separators carbon-adsorption system (T-169 & T-170 carbon canisters) on a regular schedule according to the requirements contained in 40 CFR 60, Subpart QQQ, Section 60.695(a)(3)(ii) and 40 CFR 61 Subpart FF, Section 61.354(d). The existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis, when the wastewater treatment is operational. The time period may be revised by the Department in the event that the carbon absorption system is upgraded or physically altered (ARM 17.8.749).

6. Phillips 66 shall supply the Department's Permitting and Compliance Division with the reports as required by 40 CFR 61, Subpart FF, NESHAP for Benzene Waste Operations, for requirements not overridden by 40 CFR 63, Subpart CC (ARM 17.8.749).

7. Phillips 66 shall keep all records and furnish all reports to the Department as required by 40 CFR 63, Subpart R, NESHAPs for Gasoline Distribution Facilities. These reports shall include information described in 40 CFR 63.424, 63.427, and 63.428 (ARM 17.8.749).

8. Phillips 66 shall keep all records and furnish all reports to the Department as required by 40 CFR 63, Subpart CC, NESHAPs for Petroleum Refineries (MACT I) (ARM 17.8.749).

9. Phillips 66 shall keep all records and furnish all reports to the Department as required by 40 CFR 63, Subpart UUU, NESHAPs for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (MACT II) (ARM 17.8.749).

10. Phillips 66 shall keep all records and furnish all reports to the Department as required by 40 CFR 63, Subpart EEEE, NESHAPs for Organic Liquids Distribution (Non-Gasoline) (ARM 17.8.749).

H. Operational Reporting Requirements

1. Phillips 66 shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the most recent emission inventory report and sources identified in this permit.

Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information is required for the annual emission inventory and to verify compliance with permit limitations. The information supplied shall include the following (ARM 17.8.505):

a. Sources – Phillips 66

Emission Point	**Source**	**Consumption**
Refinery		
1	**Boilers** - Four (4): #B-1, #B-2, #B-5, #B-6	MMscf of gas, %H_2S, gal of fuel oil, %S
 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 20 21 28 29 35 43	**Heaters** ["22-Fuel-Gas- Heaters"]: #1 #2 #4 #5 Coke Heater (H-3901) #10: No.2 HDS #11: No.2 HDS Debutanizer Reboiler #12: No.2 HDS Main Frac. Reboiler #13: Catalytic Reforming Unit #2 #14: Catalytic Reforming Unit #2 #15 #16: Saturated Gas Stabilizer Reboiler and PB Merox Disulfide Offgas #17 #18 #19 #20 #21 #23: Catalytic Reforming	MMscf of gas, %H_2S

Emission Point	Source	Consumption
	Unit #2 #24 Recycle Hydrogen Heater (H-8401) Fractionator Feed Heater (H-8402) No. 1 H_2 Reformer Heater (H-9401) No. 2 H_2 Reformer Heater (H-9701)	
22	FCCU	Tons of SO_2/yr
23	Refinery Main Plant Relief Flare	Tons of SO_2/yr
24	Storage Tanks	Tons of VOC losses/yr
25	Bulk Loading	Gallons of Gasoline and Gallons of Distillate Throughput
26	Fugitive VOC Emissions	i. The number of the following fugitive VOC emission sources in service subject to 40 CFR 60, Subparts GGG or GGGa. a. Gas valves b. Light liquid valves c. Heavy liquid valves d. Hydrogen valves e. Open-end valves f. Flanges g. Pump seals/light liquid h. Pump seals/heavy liquid
		ii. The number of the following fugitive VOC emission sources in service not subject to 40 CFR 60, Subparts GGG or GGGa. a. Valves b. Flanges c. Pump seals d. Compressor seals e. Relief valves f. Oil/water separators iii. Process drains iv. Wastewater handling v. Coker drill water handling
27	CPI Separator Tanks	Gallons of wastewater throughput
30	No.1 Hydrogen Plant SMR Heater (22.0 MMscfd)	MMscf of natural gas MMscf of PSA gas
32	Saturate Gas Plant	Monitoring and Maintenance Records
41 42	No.5 HDS Charge Heater No.5 HDS Stabilizer Reboiler Heater	MMscf of gas, %H_2S
45 46	No.2 H_2 Unit PSA Offgas Vent Tons of CO/yr No.1 H_2 Unit PSA	Tons CO/yr

Emission Point	Source	Consumption
	Offgas Vent	
47	Temporary Natural Gas Boiler	Hours of operation and MMscf of natural gas
51	Engine CG3810 (Backup Coke Crusher)	Maximum sulfur content of the diesel fuel used.
52	Delayed Coking Unit-Vent VOC	Cycles per year
	Delayed Coking Unit-Drum Coke Cutting VOC	Cycles per year
54	Railcar Clarified Oil Loading	Clarified Oil
Jupiter		
1	Main ATS Stack a. ATS unit b. Elemental sulfur unit	Tons of Product Produced
2	Jupiter Flare – a. Ammonium sulfide unit	Tons of Product Produced

2. For reporting purposes, the equipment should be identified using the emission point numbers specified (ARM 17.8.749).

3. Phillips 66 shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

I. Notification

Phillips 66 shall provide the Department with written notification of the following dates within the specified time periods.

1. Pretest information forms must be completed and received by the Department no later than 25 working days prior to any proposed test date, according to the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

2. The Department must be notified of any proposed test date 10 working days before that date, according to the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

3. For every time the Temporary Boiler is brought onsite, Phillips 66 shall provide written notification to the Department of the initiation of operation within 15 days. The notification will include the year of construction, and natural gas firing rate (ARM 17.8.749).

J. Vacuum Improvement Project (effective upon startup of the specified unit):

1. Modified Small Crude Unit Heater (H-1):

a. Conditions and Limitations:

1. Phillips 66 shall not burn in the Small Crude Unit Heater (H-1) any fuel that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H_2S in excess of 50 ppmv determined daily on a 365 successive calendar day rolling average basis. (ARM 17.8.749)

2. NO_X emissions from the Small Crude Unit Heater shall not exceed 0.030 lb/MMBtu on a higher heating value basis. The averaging period intended for this condition is an averaging period as would be utilized in an approved source test protocol accepted in accord with the Montana Source Test Protocol and Proceedures Manual. (ARM 17.8.749)

3. Emissions from the Small Crude Unit Heater (H-1) shall not exhibit an opacity of 10% or greater averaged over 6 consecutive minutes. (ARM 17.8.749)

4. Phillips 66 shall comply with all requirements of 40 CFR 60 Subpart J, as applicable to the Small Crude Unit Heater (H-1). (ARM 17.8.340 and 40 CFR 60 Subpart J)

5. Phillips 66 shall comply with all requirements of 40 CFR 63 Subpart DDDDD as applicable to the Small Crude Unit Heater (H-1) as an existing process heater designed to burn gas category 1. (ARM 17.8.749, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD)

6. Emissions from the Small Crude Unit Heater (H-1) shall be included in the following combined SO_2 emissions limitation applicable to the sum of emissions from all process heaters located at the refinery (ARM 17.8.749, originating from Billings/Laurel SO_2 SIP):

a. 87.0 lb/block 3-hr period
b. 696 lb per calendar day
c. 254,040 lb per calendar year

b. Testing and Compliance Demonstration:

1. Within 180 days of startup of the modified Small Crude Unit Heater (H-1), Phillips 66 shall test the Small Crude Unit Heater (H-1) for NO_X and CO, concurrently. The test shall include determination of Btu fired during the test, as well as the mass based emissions rates, and comparison to emissions factors utilized in the permit application for MAQP #2619-32. Thereafter, Phillips 66 shall test the Small Crude Unit (H-1) for NO_X and CO, concurrently, to determine emissions on a mass based emissions rate basis, as required by the Department. (ARM 17.8.749)

2. Phillips 66 shall monitor the H_2S concentration in fuel gas utilizing the fuel gas monitoring methodologies described in 40 CFR 60 Subpart Ja. (ARM 17.8.749)

3. Within 90 days of startup of the modified Small Crude Unit Heater (H-1), Phillips 66 shall conduct an initial visual observation of the Small Crude Unit Heater (H-1). Visual observation shall occur during normal operation in daylight hours. The observer need not be certified to perform Method 9 testing, however, the observer must be trained and knowledgeable regarding the effects of background contrast, ambient lighting, observer position relative to lighting, wind, and the presence of uncombined water (condensing water vapor) on the visibility of emissions. Phillips 66 shall record the date, time, observers printed and signed name and affiliation, estimated distance and direction to the stack, estimated wind direction, and results of the observation (no visible emissions or presence of visible emissions). Visual observation shall be no less than 3 six minute periods within any one hour. If the visual observation notes no visible emissions, no further testing shall be required to fulfill this initial startup test. If visual emissions are observed, Phillips 66 shall conduct a Method 9 source test as soon as reasonably possible. Thereafter, Phillips 66 shall conduct Method 9 source tests as required by the Department. (ARM 17.8.749)

4. Phillips 66 shall conduct emissions testing of the Small Crude Unit Heater (H-1) as requested by the Department. (ARM 17.8.749)

c. Notification:

1. Phillips 66 shall provide the Department written notification of startup of the modified Small Crude Unit Heater (H-1) within 30 days of startup, as determined by the earlier of postmark or email date (ARM 17.8.749).

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2. Modified Large Crude Unit Heater (H-24):

a. Conditions and Limitations:

1. Phillips 66 shall not burn in the Large Crude Unit Heater (H-24) any fuel that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60 Subpart Ja) and H_2S in excess of 50 ppmv determined daily on a 365 successive calendar day rolling average basis. (ARM 17.8.752)

2. Phillips 66 shall equip the Large Crude Unit Heater (H-24) with Ultra-Low NO_X burners, replacing the current burners. NO_X emissions from the Large Crude Unit Heater (H-24) shall not exceed 0.040 lb/MMBtu on a 30-day rolling average basis. (ARM 17.8.749, ARM 17.8.752, ARM 17.8.340, and 40 CFR 60 Subpart Ja)

3. Phillips 66 shall minimize VOC, CO and PM emissions through complying with applicable requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.752). Phillips 66 shall comply with all requirements of 40 CFR 63 Subpart DDDDD as applicable to the Large Crude Unit Heater (H-24) as a reconstructed process heater designed to burn gas category 1. (ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD)

4. Emissions from the Large Crude Unit Heater (H-24) shall not exhibit an opacity of 10% or greater averaged over 6 consecutive minutes. (ARM 17.8.752)

5. Phillips 66 shall comply with all applicable requirements of 40 CFR 60 Subpart Ja as applicable to the Large Crude Unit Heater. (ARM 17.8.340 and 40 CFR 60 Subpart Ja)

6. Emissions from the Large Crude Unit Heater (H-24) shall be included in the following combined SO_2 emissions limitation applicable to the sum of emissions from all process heaters located at the refinery (ARM 17.8.749):

a. 87.0 lb/block 3-hr period
b. 696 lb per calendar day
c. 254,040 lb per calendar year

b. Testing and Compliance Demonstration:

1. Phillips 66 shall install, operate, calibrate and maintain CEMS for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_X emissions into the atmosphere and shall determine the F factor of the fuel gas

stream no less frequently than once per day. F factor determination and CEMS equipment, operation, calibration, performance evaluation, and emissions recording shall be accomplished utilizing the methodologies described and referenced in 40 CFR 60 Subpart Ja, and shall include O_2 monitoring. (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja)

2. Phillips 66 shall test the Large Crude Unit Heater (H-24) for NO_X and CO, concurrently, within 180 days after startup of the modified Large Crude Unit Heater (H-24). The test shall include determining the BTU fired during the test, as well as the mass based emission rates and comparison to emissions factors utilized in the permit application for MAQP #2619-32. Thereafter, Phillips 66 shall test the Large Crude Unit Heater (H-24) for CO, concurrently with NO_X, to determine emissions on a mass rate basis, as required by the Department. (ARM 17.8.749)

3. Phillips 66 shall monitor the H_2S concentration in fuel gas utilizing the fuel gas monitoring methodologies described in 40 CFR 60 Subpart Ja. (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja)

4. Within 90 days of startup of the modified Large Crude Unit Heater (H-24), Phillips 66 shall conduct an initial visual observation of the Large Crude Unit Heater (H-24). Visual observation shall occur during normal operation in daylight hours. The observer need not be certified to perform Method 9 testing, however, the observer must be trained and knowledgeable regarding the effects of background contrast, ambient lighting, observer position relative to lighting, wind, and the presence of uncombined water (condensing water vapor) on the visibility of emissions. Phillips 66 shall record the date, time, observers printed and signed name and affiliation, estimated distance and direction to the stack, estimated wind direction, and results of the observation (no visible emissions or presence of visible emissions). Visual observation shall be no less than 3 six minute periods in any one hour. If the visual observation notes no visible emissions, no further testing shall be required to fulfill this initial startup test. If visual emissions are observed, Phillips 66 shall conduct a Method 9 source test as soon as reasonably possible. Thereafter, Phillips 66 shall conduct visual observation or Method 9 source tests as required by the Department. (ARM 17.8.749)

5. Phillips 66 shall conduct emissions testing of the Large Crude Unit Heater (H-24) as requested by the Department. (ARM 17.8.749)

c. Notification:

1. Phillips 66 shall provide the Department written notification of startup of the modified Large Crude Unit Heater (H-24) within 30 days of startup, as determined by the earlier of postmark or email date. (ARM 17.8.749)

3. New Vacuum Furnace (H-17)

a. Conditions and Limitations:

1. At no time shall Phillips 66 have emissions from both the existing and new Vacuum Furnace. Phillips 66 shall permanently remove from service the existing Vacuum Furnace. The existing Vacuum Furnace shall be made physically incapable of service, and/or removed from the site. (ARM 17.8.749)

2. Phillips 66 shall not burn in the Vacuum Furnace (H-17) fuel gas containing H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60 Subpart Ja) and 50 ppmv determined daily on a 365 successive calendar day rolling average basis. (ARM 17.8.752)

3. NO_X emissions from the Vacuum Furnace (H-17) shall not exceed 0.030 lb/MMBtu on a higher heating value basis, determined daily on a 30-day rolling average basis. (ARM 17.8.752)

4. Phillips 66 shall minimize VOC, CO and PM emissions through complying with applicable requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.752). Phillips 66 shall comply with all requirements of 40 CFR 63 Subpart DDDDD as applicable to the Vacuum Furnace (H-17) as a new gas category 1 process heater (ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).

5. Emissions from the Vacuum Furnace (H-17) shall not exhibit an opacity of 10% or greater averaged over 6 consecutive minutes. (ARM 17.8.752)

6. Phillips 66 shall comply with all applicable requirements of 40 CFR 60 Subpart Ja, as applicable to the Vacuum Furnace (H-17). (ARM 17.8.340 and 40 CFR 60 Subpart Ja)

7. Emissions from the Vacuum Furnace (H-17) shall be included in the following combined SO_2 emissions limitation applicable to the sum of emissions from all process heaters located at the refinery (ARM 17.8.749):

a. 87.0 lb/block 3-hr period
b. 696 lb per calendar day
c. 254,040 lb per calendar year

b. Testing and Compliance Demonstration:

1. Phillips 66 shall monitor the H_2S concentration in fuel gas utilizing the fuel gas monitoring methodologies described in 40 CFR 60 Subpart Ja. (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja)

2. Phillips 66 shall install, operate, calibrate and maintain CEMS for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_X emissions into the atmosphere and shall determine the F factor of the fuel gas stream no less frequently than once per day. F factor determination and CEMS equipment, operation, calibration, performance evaluation, and emissions recording shall be accomplished utilizing the methodologies described and referenced in 40 CFR 60 Subpart Ja, and shall include O_2 monitoring. (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja)

3. Phillips 66 shall test the Vacuum Furnace (H-17) for NO_X and CO, concurrently, within 180 days after startup of the new Vacuum Furnace (H-17). The test shall include determination of Btu fired during the test, as well as the mass based emissions rates and comparison to emissions factors utilized in the permit application for MAQP #2619-32. Thereafter, Phillips 66 shall test the Vacuum Furnace (H-17) for CO, concurrently with NO_X, to determine emissions on a mass rate basis, as required by the Department. (ARM 17.8.749)

4. Within 90 days of startup of the Vacuum Furnace (H-17), Phillips 66 shall conduct an initial visual observation of the Vacuum Furnace (H-17). Visual observation shall occur during normal operation in daylight hours. The observer need not be certified to perform Method 9 testing, however, the observer must be trained and knowledgeable regarding the effects of background contrast, ambient lighting, observer position relative to lighting, wind, and the presence of uncombined water (condensing water vapor) on the visibility of emissions. Phillips 66 shall record the date, time, observers printed and signed name and affiliation, estimated distance and direction to the stack, estimated wind direction, and results of the observation (no visible emissions or presence of visible emissions). Visual observation shall be no less than 3 six minute periods in any one hour. If the visual observation notes no visible emissions, no further testing

shall be required to fulfill this initial startup test. If visual emissions are observed, Phillips 66 shall conduct a Method 9 source test as soon as reasonably possible. Thereafter, Phillips 66 shall conduct Method 9 source tests as required by the Department. (ARM 17.8.749)

5. Phillips 66 shall conduct emissions testing of the Vacuum Furnace (H-17) as requested by the Department (ARM 17.8.749).

6. Emissions from the Vacuum Furnace (H-17) shall be included in the following combined SO_2 emissions limitation applicable to the sum of emissions from all process heaters located at the refinery (ARM 17.8.749):

   a. 87.0 lb/block 3-hr period
   b. 696 lb per calendar day
   c. 254,040 lb per calendar year

c. Notification:

1. Phillips 66 shall provide the Department written notification of the date of startup of the new Vacuum Furnace Heater (H-17) within 30 days of startup, as determined by the earlier of postmark or email date. (ARM 17.8.749)

2. Phillips 66 shall provide the Department written notification of the date of removal from service the existing Vacuum Furnace Heater within 30 days of removal from service. (ARM 17.8.749)

4. Modified No. 1 H_2 Unit Reformer Heater (H-9401):

a. Conditions and Limitations:

1. The No. 1 H_2 Unit Reformer Heater (H-9401) shall burn only natural gas, PSA off-gas, and/or cryo off-gas, which are inherently low sulfur fuels (ARM 17.8.749).

2. NO_X emissions from the No. 1 H_2 Unit Reformer Heater (H-9401) shall not exceed 0.030 lb/MMBtu on a higher heating value basis. The averaging period intended for this condition is an averaging period as would be utilized in an approved source test protocol accepted in accord with the Montana Source Test Protocol and Proceedures Manual (ARM 17.8.749).

3. Phillips 66 shall minimize VOC, CO and PM emissions through complying with applicable requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.752). Phillips 66 shall

comply with all requirements of 40 CFR 63 Subpart DDDDD as applicable to the No. 1 H_2 Unit Reformer Heater (H-9401) as an existing process heater designed to burn gas category 1 (ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).

4. Phillips 66 shall comply with all requirements of 40 CFR 60 Subpart J, as applicable to the No. 1 H_2 Unit Reformer Heater (H-9401). (ARM 17.8.340 and 40 CFR 60 Subpart J)

5. Emissions from the No. 1 H_2 Unit Reformer Heater (H-9401) shall be included in the following combined SO_2 emissions limitation applicable to the sum of emissions from all process heaters located at the refinery (ARM 17.8.749):

   a. 87.0 lb/block 3-hr period
   b. 696 lb per calendar day
   c. 254,040 lb per calendar year

b. Testing and Compliance Demonstration:

1. Phillips 66 shall test the No. 1 H_2 Unit Reformer Heater (H-9401) for NO_X and CO, concurrently, within 180 days after startup of the modified No. 1 H_2 Unit Reformer Heater (H-9401). The test shall include determination of Btu fired during the test, as well as the mass based emissions rates and comparison to emissions factors utilized in the permit application for MAQP #2619-32. Thereafter, Phillips 66 shall test the No. 1 H_2 Unit Reformer Heater (H-9401) for NO_X and CO concurrently, on a mass based emissions rate basis, as required by the Department. (ARM 17.8.749)

2. Phillips 66 shall conduct emissions testing of the No. 1 H_2 Unit Reformer Heater (H-9401) as requested by the Department. (ARM 17.8.749)

c. Notification:

1. Phillips 66 shall provide the Department written notification of startup of the modified No. 1 H2 Unit Reformer Heater (H-9401) within 30 days of startup, as determined by the earlier of postmark or email date. (ARM 17.8.749)

5. Jupiter Sulfur Recovery Units (Modified #1, Existing #2, and New #3)

a. Conditions and Limitations:

1. Emissions from the Jupiter Main Stack No. 1 shall not exceed the following (ARM 17.8.749):

a. SO_2 emissions: 25 lb/hr, 167 ppmvd at 0% O_2 on a rolling 12-hour average basis
b. CO emissions: 4.22 lb/hr
c. NO_X emissions: 14.84 lb/hr
d. PM_{10} emissions: 1.61 lb/hr
e. $PM_{2.5}$ emissions: 1.61 lb/hr
f. Ammonia emissions: 13.36 lb/hr
g. Opacity: 20% averaged over 6 consecutive minutes

2. Sulfur Recovery Unit #3 (SRU #3) shall be installed with it's own separate emissions stack (Jupiter Main Stack No. 2). (ARM 17.8.749)

3. CO emissions from SRU #3 shall not exceed 4.22 lb/hr. (ARM 17.8.752)

4. NO_X emissions from SRU #3 shall not exceed 14.84 lb/hr. (ARM 17.8.752)

5. PM_{10} emissions from SRU #3 shall not exceed 1.61 lb/hr. (ARM 17.8.752)

6. $PM_{2.5}$ emissions from SRU #3 shall not exceed 1.61 lb/hr. (ARM 17.8.752)

7. SO_2 emissions from SRU #3 shall not exceed 18.33 lb/hr. (ARM 17.8.749, ARM 17.8.752).

8. Opacity emissions from SRU #3 shall not exceed 20% averaged over 6 consecutive minutes. (ARM 17.8.752 and ARM 17.8.304)

9. Ammonia emissions from SRU #3 shall not exceed 13.36 lb/hr. (ARM 17.8.749)

10. Phillips 66 shall control SO_2 emissions from SRU #3 by using an oxidation tail gas scrubber process. SO_2 emissions from the SRU #3 shall not exceed 167 ppmvd (dry basis, at 3% excess oxygen), based on a rolling 12-hour average. (ARM 17.8.752)

11. Phillips 66 shall comply with all applicable requirements of 40 CFR 60 Subpart Ja, as applicable to SRU #1 and SRU #3. (ARM 17.8.340 and 40 CFR 60 Subpart Ja)

12. SRU #2 shall be considered subject to 40 CFR 60 Subpart Ja conditions as a modified unit. (ARM 17.8.749)

13. Phillips 66 shall comply with all applicable requirements of 40 CFR 63 Subpart UUU, as applicable to SRU #1, SRU #2, and SRU #3. (ARM 17.8.342 and 40 CFR 63 Subpart UUU)

14. Emissions from the Jupiter Main Stack No. 1 and No. 2, combined, shall not exceed the following (ARM 17.8.749 for PSD Avoidance Purposes):

    a. SO_2 emissions from the Jupiter Main Stack No. 1 and Jupiter Main Stack No. 2 combined shall not exceed 50.00 tons per year, determined monthly on a rolling 12 month basis;

    b. NO_X emissions from the Jupiter Main Stack No. 1 and Jupiter Main Stack No. 2 combined shall not exceed 65.00 tons per year, determined monthly on a rolling 12 month basis;

    c. CO emissions from the Jupiter Main Stack No. 1 and Jupiter Main Stack No. 2 combined shall not exceed 18.46 tons per year, determined monthly on a rolling 12 month basis;

    d. PM_{10} emissions from the Jupiter Main Stack No. 1 and Jupiter Main Stack No. 2 combined shall not exceed 7.06 tons per year, determined monthly on a rolling 12 month basis;

    e. $PM_{2.5}$ emissions from the Jupiter Main Stack No. 1 and Jupiter Main Stack No. 2 combined shall not exceed 7.06 tons per year, determined monthly on a rolling 12 month basis;

    f. Ammonia emissions from the Jupiter Main Stack No. 1 and Jupiter Main Stack No. 2 shall not exceed 117 tons per year, determined monthly on a rolling 12 month basis

b. Testing and Compliance Demonstration:

1. Phillips 66 shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of any SO_2 emissions into the atmosphere on Jupiter Main Stack No. 1 and Jupiter Main Stack No. 2. The monitors shall include an oxygen monitor for correcting the data for excess air, and flow rate monitors. The CEMS shall meet all applicable requirements of 40 CFR 60 Subpart Ja, which also references 40 CFR 60.13(c) and Performance Specification 2 of Appendix B of 40 CFR 60. (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja)

2. Daily SO_2 and flow rate data from the Jupiter Main Stack No. 1 and Jupiter Main Stack No. 2 CEMS shall be reported quarterly. The quarterly report shall include the combined monthly and rolling 12-month sum SO_2 emissions for each calendar month. (ARM 17.8.749)

3. Phillips 66 shall perform NO_X and CO testing concurrent with the SO_2 relative accuracy evaluations required for CEMS performance testing on the Jupiter Main Stack No. 1 and Jupiter Main Stack No. 2 to determine a NO_X and CO emissions factor for use in estimating emissions. Phillips 66 shall perform additional NO_X and/or CO testing as required by the Department. (ARM 17.8.749)

4. NO_X emissions shall be estimated and recorded monthly, and the rolling 12 month sum calculated and recorded. These data shall be reported with the SO_2 quarterly report. (ARM 17.8.749)

5. CO emissions shall be estimated and recorded monthly, and the rolling 12 month sum calculated and recorded. These data shall be reported with the SO_2 quarterly report. (ARM 17.8.749)

6. PM_{10} and $PM_{2.5}$ emissions shall be estimated and recorded monthly, and the rolling 12 month sum calculated and recorded. These data shall be reported with the SO_2 quarterly report. (ARM 17.8.749)

7. Ammonia emissions shall be estimated based on mass balance equations, and recorded monthly, along with the rolling 12 month sum for each month. These data shall be reported with the SO_2 quarterly report. (ARM 17.8.749)

6. Piping and Wastewater Component Type Fugitive Emissions

a. Conditions and Limitations:

1. Phillips 66 shall comply with all applicable requirements of 40 CFR 60 Subpart GGGa as applicable to the equipment in the Small CTU, Large CTU, Vacuum Unit, No. 2 HDS Unit, and No. 4 HDS Unit. (ARM 17.8.752, ARM 17.8.340 and 40 CFR 60 Subpart GGGa)

2. Phillips 66 shall comply with all applicable requirements of 40 CFR 60 Subpart QQQ as applicable to the new individual drain system and the aggregate facility as described in the subpart, installed in the Vaccum Unit. (ARM 17.8.752, ARM 17.8.340 and 40 CFR 60 Subpart QQQ).

3. Phillips 66 shall comply with all applicable requirements of 40 CFR 60 Subpart QQQ as applicable to the modified individual drain system in the No. 2 HDS Unit. (ARM 17.8.752, ARM 17.8.340 and 40 CFR 60 Subpart QQQ)

4. Phillips 66 shall comply with all applicable requirements of 40 CFR 63 Subpart CC including as applicable to piping components in the Large Crude Topping/Vacuum Unit, the Small Crude Topping Unit, the No. 2 HDS Unit, and the No. 4 HDS Unit (ARM 17.8.752, ARM 17.8.340 and 40 CFR 60 Subpart GGGa; ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart CC).

5. Phillips 66 shall comply with 40 CFR 61 Subpart FF as applicable to individual drain systems. (ARM 17.8.341 and 40 CFR 61 Subpart FF)

b. Notification:

1. Phillips 66 shall provide written notification of completion, and provide the Department with a final estimated count of components, organized by component type and associated Unit (Large Crude Topping/Vacuum Unit, the Small Crude Topping Unit, the No. 2 HDS Unit, and the No. 4 HDS Unit), within 180 days of completion of piping associated with each unit, as determined by the earlier of email date or postmark date. (ARM 17.8.749)

7. New API Separator Tanks (2 new tanks)

a. Conditions and Limitations:

1. The separator bays of the two New API Separator Tanks shall be covered and sealed and the vapor from these bays shall be routed to a VOC control device to control VOC emissions with at least a 95% control efficiency. (ARM 17.8.752) The VOC control device shall be an activated carbon canister. (ARM 17.8.749)

2. Phillips 66 shall comply with all applicable requirements of 40 CFR 60 Subpart QQQ as applicable to the two (2) New API Separator Tanks. (ARM 17.8.340 and 40 CFR 60 Subpart QQQ)

3. Phillips 66 shall comply with 40 CFR 63 Subpart CC as applicable to the two New API Separator Tanks. (ARM 17.8.342 and 40 CFR 63 Subpart CC)

4. Phillips 66 shall comply with 40 CFR 61 Subpart FF as applicable to the New API Separator Tanks (ARM17.8.341 and 40 CFR 61 Subpart FF).

5. Phillips 66 shall permanently remove from current service the Coker Break Tanks (T-4512 and T4513), the Primary Oil Water Separater (T-163), and the CPI Oil Water Separator (T-169 and T-170). (ARM 17.8.749)

b. Notification:

1. Phillips 66 shall provide the Department written notification of startup of the New API Separator Tanks within 30 days of startup, as determined by the earlier of postmark or email date. (ARM 17.8.749)

2. Phillips 66 shall provide the Department written notification of removal from service the Coker Break Tanks (T-4512 and T4513), the Primary Oil Water Separator (T-163), and the CPI Oil Water Separator (T-169 and T-170). (ARM 17.8.749)

8. New Cooling Tower

a. Conditions and Limitations:

1. Phillips 66 shall limit PM, PM_{10}, and $PM_{2.5}$ emissions from the New Wet Cooling Tower EPN 53 using a high efficiency drift eliminator, designed for no more than a 0.0010% drift rate. (ARM 17.8.752)

2. The maximum conductivity of water in the cooling tower shall not exceed 3,130 microsiemens per centimeter (μS/cm) at 25 degrees celcius. (ARM 17.8.749)

3. Phillips 66 shall comply with 40 CFR 63 Subpart CC as applicable to all heat exchange systems, as defined in this subpart. (ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart CC)

4. Phillips 66 shall comply with 40 CFR 63 Subpart Q as applicable to the New Cooling Tower. (ARM 17.8.342 and 40 CFR 63 Subpart Q)

b. Testing and Demonstration:

1. Phillips 66 shall maintain documentation, written and provided by the vendor/manufacturer, of the final and approved specification sheet clearly indicating the design drift rate of the New Wet Cooling Tower EPN 53. (ARM 17.8.749)

2. Phillips 66 shall test a representative grab sample of cooling water tower water for conductivity at least once per calendar quarter, or according to another schedule as may be approved by the Department. Method 120.1 conductivity test proceedures, as found for use under 40 CFR 136, or other methods as may be approved by the Department in advance, shall be utilized. (ARM 17.8.749)

c. Notification:

1. Phillips 66 shall provide the Department written notification of startup of the New Wet Cooling Tower within 30 days of startup, as determined by the earlier of postmark or email date. (ARM 17.8.749)

9. New Jupiter Cooling Tower CT-602

a. Conditions and Limitations:

1. Phillips 66 shall limit PM, PM_{10}, and $PM_{2.5}$ emissions from the New Jupiter Cooling Tower CT-602 using a high efficiency drift eliminator, designed for no more than a 0.0010% drift rate. (ARM 17.8.752)

2. The maximum conductivity of water in the cooling tower shall not exceed 3,130 microsiemens per centimeter (μS/cm) at 25 degrees celcius. (ARM 17.8.749)

3. Phillips 66 shall comply with 40 CFR 63 Subpart CC as applicable to all heat exchange systems, as defined in this subpart. (ARM 17.8.752, ARM 17.8.342, and 40 CFR 63 Subpart CC)

4. Phillips 66 shall comply with 40 CFR 63 Subpart Q as applicable to the New Jupiter Cooling Tower CT-602. (ARM 17.8.342 and 40 CFR 63 Subpart Q)

b. Testing and Demonstration:

1. Phillips 66 shall maintain documentation, written and provided by the vendor/manufacturer, of the guaranteed design drift rate of the Jupiter Cooling Tower CT-602. (ARM 17.8.749)

2. Phillips 66 shall test a representative grab sample of cooling water tower water for conductivity at least once per calendar quarter, or according to another schedule as may be approved by the Department. Method 120.1 conductivity test proceedures, as found for use under 40 CFR 136, or other methods as may be approved by the Department in advance, shall be utilized. (ARM 17.8.749)

c. Notification:

1. Phillips 66 shall notify the Department of startup of the New Jupiter Cooling Tower CT-602 within 30 days of startup, as determined by the earlier of postmark or email date. (ARM 17.8.749)

SECTION III: General Conditions

A. Inspection - The recipient shall allow the Department's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver - The permit and all the terms, conditions, and matters stated herein shall be deemed accepted if the recipient fails to appeal as indicated below.

C. Compliance with Statutes and Regulations - Nothing in this permit shall be construed as relieving the permittee of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*. (ARM 17.8.756).

D. Enforcement - Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties, or other enforcement as specified in Section 75-2-401 *et seq*., MCA.

E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

F. Permit Inspection - As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by the Department at the location of the source.

G. Duration of Permit – Construction or installation must begin or contractual obligations entered into that would constitute substantial loss within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall expire (ARM 17.8.762).

H. Permit Fees - Pursuant to Section 75-2-220, MCA, failure to pay the annual operation fee by the permittee may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

Montana Air Quality Permit Analysis
Phillips 66 Company, Billings Refinery
Montana Air Quality Permit (MAQP) #2619-32

I. Introduction/Process Description

A. Source Description – Phillips 66

The Phillips 66 Company, Billings Refinery (Phillips 66) is located at 401 South 23rd Street, Billings, Montana, in the NW¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County. The refinery property is adjacent to the City of Billings and is next to Interstate 90 and the Yellowstone River. Residential properties exist on the west side of the refinery and the United States Postal Service has an office located on the south side of the property.

The refinery has the capability to process an annual average of approximately 72,500 barrels per day of crude oil and produces a wide range of petroleum products, including propane, gasoline, kerosene/jet fuel, diesel, and petroleum coke. All previously permitted equipment, limitations, conditions, and reporting requirements stated in MAQPs #1719, #2565, #2669, #2619, and #2619A were included in MAQP #2619-02.

Emission Point	Source
Refinery	
1	**Boilers** - Four (4): #B-1, #B-2, #B-5, #B-6
	Heaters ["22-Fuel-Gas-Heaters"]:
2	#1
3	#2
4	#4
5	#5
6	Coke Heater (H-3901)
7	#10: No.2 HDS
8	#11: No.2 HDS Debutanizer Reboiler
9	#12: No.2 HDS Main Frac. Reboiler
10	#13: Catalytic Reforming Unit #2
11	#14: Catalytic Reforming Unit #2
12	#15
13	#16: Saturated Gas Stabilizer Reboiler and PB Merox Disulfide Offgas
14	#17
15	#18
16	#19
17	#20
18	#21
20	#23: Catalytic Reforming Unit #2
21	#24
28	Recycle Hydrogen Heater (H-8401)
29	Fractionator Feed Heater (H-8402)
35	No. 1 H_2 Reformer Heater (H-9401)
43	No. 2 H_2 Reformer Heater (H-9701)

Emission Point	Source
22	FCCU
23	Refinery Main Plant Relief Flare
24	Storage Tanks
25	Bulk Loading
26	Fugitive VOC Emissions
27	Corrugated Plate Interceptor (CPI) Separator Tanks
30	No.1 Hydrogen Plant SMR Heater (H-9401) (22.0 million standard cubic feet per day (MMscfd))
32	Saturate Gas Plant
41 42	No.5 HDS Charge Heater No.5 HDS Stabilizer Reboiler Heater
45 46	No.2 H_2 Unit PSA Offgas Vent No.1 H_2 Unit PSA Offgas Vent
47	Temporary Natural Gas Boiler
51	Engine associated with CG3810 used for operation of the Backup Coke Crusher
52	Delayed Coking Unit

B. Source Description – Jupiter Sulphur, LLC

Jupiter Sulphur, LLC (Jupiter) operates a sulfur recovery operation, within the petroleum refinery area described above, at 2201 7th Avenue South, Billings, Montana. The facility is operated as a joint venture, of which Phillips 66 is a partner. Phillips 66 is responsible for maintaining air permit compliance at Jupiter's sulfur recovery facility.

Jupiter's total sulfur recovery capacity is 295 Long Tons per Day (LT/D) of sulfur. The Jupiter facility consists of three primary units: the Ammonium Thiosulfate (ATS) Plant, the Ammonium Sulfide Unit (ASD), and the Claus Sulfur and Tail Gas Treating Units (TGTUs).

Jupiter's new Claus Sulfur and TGTUs shall have three parallel single-stage high-efficiency gas filters for final particulate and sulfur dioxide (SO_2) control. All emissions from these three primary processes are vented to Jupiter's main stack.

Emission Point	Source
1	Main ATS Stack a. ATS unit b. Elemental sulfur unit
2	Jupiter Flare – a. Ammonium sulfide unit

C. Permit History

On October 29, 1982, Conoco Inc. (Conoco) received an air quality permit for an emergency flare stack to be equipped and operated with steam injection. This application was given **MAQP #1719**.

On June 2, 1989, Conoco received an air quality permit to convert an existing 5,000-barrel cone roof tank (#49) to an internal floating roof with double seals. This conversion was necessary in order to switch service from diesel to aviation gasoline storage. The application was given **MAQP #2565**.

On January 29, 1991, Conoco received an air quality permit to construct and operate two 2,000-barrel desalter wastewater break tanks equipped with external floating roofs and double-rim seals. The new tanks were to augment the refinery's ability to control fugitive Volatile Organic Compounds (VOC) emissions and enhance recovery of oily water from the existing wastewater treatment system. The application was given **MAQP #2669**.

On April 19, 1990, Conoco received an air quality permit to construct new equipment and modify existing equipment at the refinery and to construct a sulfur recovery facility, operated by Kerley Enterprises under the control of Conoco, as part of the overall Conoco project. The application was given **MAQP #2619**.

Conoco was permitted to construct a new 13,000-barrels-per-stream-day delayed petroleum coker unit, cryogenic gas plant, gasoline treating unit, and hydrogen system additions. Also, modifications to the existing crude and vacuum distillation units, hydrodesulfurization units, amine treating units and wastewater treatment system were permitted.

Conoco was also permitted to construct a sulfur recovery facility (SRU)/ATS to be operated by Kerley Enterprises. This facility is operated in conjunction with the new installations and modifications at the Conoco Refinery. This facility was permitted with the capability of utilizing 109.9 LT/D of equivalent sulfur obtained from the Conoco Refinery for the manufacture of elemental sulfur and sulfur-containing fertilizer solutions (i.e., ATS).

On December 4, 1991, Conoco was issued **MAQP #2619A** for the construction of a 1,000-barrel hydrocarbon storage tank (T-162). The new tank stores recovered hydrocarbon product from the contaminated groundwater aquifer beneath the Conoco Refinery. Over the years, surface discharges at the refinery contaminated the groundwater with oily hydrocarbon products. The purpose of this project was to recover hydrocarbon product (oil) from the groundwater aquifer beneath the refinery. The hydrocarbon product (oil) is pumped out of a cone of depression within the contaminated groundwater aquifer. Groundwater, less the recovered hydrocarbon product, is returned to the aquifer. The application addressed the increase in VOC emissions from the storage of recovered hydrocarbon product.

On March 5, 1993, Conoco was issued **MAQP #2619-02** for the construction and operation of a 5.0-MMscf-per-day hydrogen plant and to replace their existing American Petroleum Institute (API) separator system with a CPI separator system.

This permit was an alteration to Conoco's existing MAQP #2619 and included all previously permitted equipment, limitations, conditions, and reporting requirements stated in MAQPs #1719, #2565, #2669, #2619, and #2619A.

The natural gas feedstock to the new hydrogen plant produces 99.9% pure hydrogen. This hydrogen and hydrogen from the existing catalytic reformers is routed to the refinery hydrotreaters to reduce fuel product sulfur content. The Hydrogen sulfide (H_2S) produced is routed to the Jupiter SRU/ATS, operated by Kerley Enterprises, which produces sulfur and fertilizer products.

The two new CPI separator tanks with carbon canister total VOC controls were constructed to comply with 40 Code of Federal Regulations (CFR) 60, Subpart QQQ, and 40 CFR 61, Subpart FF regulations. The CPI separators were vented to two carbon canisters in series. Each carbon canister was designed and operated to reduce VOC emissions by 95% or greater, with no detectable emissions. This CPI separator system replaced the existing API separator system.

As per a letter received by the Department of Environmental Quality (Department), on December 22, 1992, ownership of the Kerley Enterprises facility was transferred to Jupiter Sulphur, Inc. as of December 31, 1992.

On September 14, 1993, Conoco was issued **MAQP #2619-03** for the construction and operation of a gas oil hydrotreater and associated hydrogen plant at the Billings Refinery. The new hydrotreater desulfurizes a mixture of Fluid Catalytic Cracker Unit (FCCU) feed gas oils, which allows the FCCU to produce low-sulfur gasoline. This low-sulfur gasoline was required by January 1, 1995, to satisfy Environmental Protection Agency's (EPA) gasoline sulfur provisions of the Federal 1990 Clean Air Act Amendments. Hydrogen requirements are met by the installation of a hydrogen plant, and sulfur recovery capacity was provided by installing additional elemental liquid sulfur production facilities at the Jupiter Sulphur, Inc. plant adjacent to the refinery.

The Gas Oil Hydrodesulfurizer (GOHDS) was designed to meet the primary objective of removing sulfur from the FCCU feedstock. A combination of gas oils feed the Gas Oil Hydrotreater. The gas oils are mixed with hydrogen, heated, and passed over a catalyst bed where desulfurization occurs. The gas oil is then fractionated into several products, cooled, and sent to storage. A steam-methane reforming hydrogen plant produces makeup hydrogen for the unit. Any unconsumed hydrogen is amine treated for hydrogen H_2S removal and recycled.

The new project did not increase refinery capacity. The project did not constitute a major modification for purposes of the New Source Review - Prevention of Significant Deterioration (NSR-PSD) program since net emissions did not increase in significant amounts as defined by the Administrative Rules of Montana (ARM) 17.8.801(20)(a).

The additional fugitive VOC emissions from this project were calculated by totaling the fugitive sources on the process units. These sources included flanges, valves, relief valves, process drains, compressor seal degassing vents and accumulator vents and open-ended lines. The fugitive source tabulation was then used with actual refinery emission factors obtained from the Conoco Refinery in Ponca City, Oklahoma. Furthermore, it was intended that each non-control valve in VOC service would be repacked with graphite packing to Conoco standards before installation. All control valves for the GOHDS project would be Enviro-Seal valves or equivalent. The Enviro-Seal valves have a performance specification that exceeds the Subpart GGG standards. The VOC emissions will be validated by 40 CFR 60, Subpart GGG, emission monitoring.

The Jupiter Sulphur, Inc. Recovery Facility consists of three primary units: the existing ATS Plant, the existing ATS Unit and the new Claus Sulfur and TGTU. The addition of the new units increased the total sulfur recovery capacity of the facility from 110 to 170 LT/D of sulfur.

The existing ATS plant consisted of a thermal Claus reaction-type boiler. The exit gas from this Claus boiler is incinerated in the ATS Unit. The SO_2 from the incinerator is absorbed and converted to ammonium bisulfite (ABS). The ABS is then used to absorb and react with H_2S to produce the ATS product. Up to 110 LT/D of sulfur can be processed by the ATS Plant to produce sulfur and ATS.

The ASD consists of an absorption column, which absorbs the sulfur as H_2S in the acid gas feed and reacts with NH_3 and water. When the new Claus Sulfur Unit was added, the Sulfur Recovery Facility was modified to incinerate any off gas from this unit in the TGTU and ATS Plant. This eliminates off-gas flow to, and emissions from, the flare. Up to 110 LT/D of sulfur can be processed by the ASD to produce ammonium sulfide solution.

The proposed Claus Sulfur Unit consisted of a thermal Claus reaction furnace, followed by a waste heat boiler and three catalytic Claus reaction beds. The Claus tail gas is then incinerated before entering the TGTU. In this new unit, SO_2 from the incinerator was absorbed and converted to ABS. This ABS is then transferred to the ATS Unit for conversion to ATS. Up to 110 LT/D of sulfur can be processed by the new Claus Sulfur Unit to produce sulfur and ABS. The ABS from the TGTU is dilute, containing a significant amount of water that was generated from the Claus reaction. To prevent making a dilute ATS from this "weak" ABS, a new ATS Reactor was added to the ATS Unit. This ATS Reactor combines "weak" ABS, additional ABS, and sulfur to make a full-strength ATS solution.

An important feature of the Jupiter Sulphur, Inc. facility is its capability to process Conoco Inc.'s sour gases at all times. A maximum of 170 LT/D of sulfur is recovered and each of the three units has a capacity of 110 LT/D. If any one of the three is out of service, then the other two can easily handle the load. While the process has 100% redundancy, any two of the three units must be running to handle the design load. The process uses high-efficiency gas filters, which employ a water-flushed coalescer cartridge to reduce particulate, as well as sulfur compounds.

On November 11, 1993, Conoco was issued **MAQP #2619-04** to construct and operate a new compressor station and associated equipment at the Billings Refinery. The C-23 compressor station project involved the recommissioning of an out-of-service compressor and associated equipment components having fugitive VOC emissions. The project also involved the installation of new equipment components having fugitive VOC emissions. The recommissioned compressor was originally installed in 1948. The compressor underwent some minor refurbishing, but did not trigger "reconstruction" as defined in 40 CFR 60.15.

The purpose of the C-23 compressor station project was to improve the economics of the refinery's wet gas (gas streams containing recoverable liquid products) processing through increased yields and more efficient operation in the refinery's large and small Crude Topping Units (CTUs) and the Alkylation Unit. The project also improved safety in the operations of the two CTUs, Alkylation Unit, and Gas Recovery Plant (GRP). As a result of this project, the vapor pressure of the alkylate product (produced by the Alkylation Unit) was lowered.

On February 2, 1994, Conoco was issued **MAQP #2619-05** to construct and operate a butane defluorinator within the alkylation unit at the refinery. Installation of an alumina (Al_2O_3) bed defluorinator system was to remove residual hydrofluoric acid (HF) and organic fluorides from the butane stream produced by the Alkylation Unit. This reduced the fluorine level of the butane from ~ 500 parts per million by weight (ppmw) to ~ 1 ppmw, which allows the butane to be recycled back to the refinery's Butamer Unit for conversion into isobutane. Refer to the permit application for a more thorough description of the process and proposed changes.

The Alkylation Unit Butane Defluorinator Project resulted in: (1) changes in operation of the alkylate stabilization train of the Alkylation Unit to yield defluorinated butane instead of fluorinated and lower vapor pressure alkylate products; (2) changes in operation of the refinery's gasoline blending to restructure butane blending and lower the vapor pressure of the gasoline pool; (3) minimized butane sales; (4) minimized butane burning as refinery fuel gas; and (5) economized gasoline blending of butane.

On March 28, 1994, Conoco was issued **MAQP #2619-06** to construct and operate equipment to support a new PMA Unit at the refinery. The PMA project allowed Conoco to produce asphalt that meets the new federal specifications and to become a supplier of PMA for the region.

Installation of a 9.5-million British thermal units per hour (MMBtu/hr) natural gas-fired process heater to heat an oil heat transfer fluid supplies heat to bring the asphalt base to 400^{o}F. This allows a polymer material to be mixed with it to produce PMA. A hot oil transfer pump was installed to circulate hot oil through the system. A heat exchanger (X-364) from the shutdown Propane De-asphalting (PDA) Unit was moved and installed to aid in the heating of the asphalt base. Two existing 5,000-bbl asphalt storage tanks were converted to PMA mixing and curing tanks. This required the installation of additional agitators, a polymer pellet loading (blower) system and conversion of the tank steamcoil heating system to hot oil heated by the new process heater. New asphalt transfer lines, a new asphalt transfer pump, and a new 5,000-bbl PMA storage tank (to replace the demolished T-50) were installed to keep the PMA separated from other asphalt products.

This permit alteration also addressed the items submitted in a letter dated November 23, 1993, for supplemental information and a request for permit clarification for Conoco's MAQP #2619-03. This permit clarifies all these items, as appropriate, including the issues relating to the redesign of the SRU stack and the addition of heated air to the stack. Reference Section VI, Air Quality Impacts.

On July 28, 1995, Conoco was issued **MAQP #2619-07** for the construction and operation of new equipment within the refinery's Alkylation (Alky) and Gas Recovery Plant/No.1 Amine Units. The project was referred to as the Alkylation Unit Depropanizer Project.

The existing Alkylation Unit was replaced with a new tower. The new depropanizer is located where the No.1 Bio-pond was located. Piping and valves were added, and existing equipment was located next to the new depropanizer. The old depropanizer was retained in place and may be used in the future in non- HF service.

The decommissioned PDA Unit evaporator tower (W-3) was converted to a water wash tower to remove entrained amine from the Alky PB (Propane/Butene) olefins upstream of the PB merox prewash. New piping, valves, and instrumentation were added around W-3.

The change in air emissions associated with this project was an increase in fugitive VOC emissions, as well as additional emission of fluorides due to the installation of the new depropanizer piping and valves.

The changes made by this project were not subject to NSR-PSD review since the sum of the emission rate increases were below PSD significant emission rates for applicable pollutants.

The drains installed or reused tie into parts of the refinery's wastewater sewer system that are already subject to Standards of Performance for New Stationary Sources (NSPS), Subpart QQQ (Wastewater Treatment System VOC Emissions in Petroleum Refineries) and National Emission Standards for Hazardous Air Pollutants (NESHAP), Subpart FF (Benzene Waste Operations). These drains were equipped with tight fitting caps and have hard pipe connections to meet the required control specifications.

On July 24, 1996, Conoco was issued **MAQP #2619-08** to change the daily SO_2 emissions limit of the 19 existing process heaters, as well as combining the 19 heaters, the Coker heater (H-3901), and the GOHDS heaters (H-8401 and H-8402) into one SO_2 point source within the Refinery. The project is referred to as the Existing Heater Optimization Project.

The 19 process heaters being discussed in this application are the process heaters (excluding H-3 and H-7) that were in operation prior to the construction of the Delayed Coker/Sulfur Reduction Project, which became fully operational in May of 1992. The 19 heaters are: H-1, H-2, H-4, H-5, H-10, H-11, H-12, H-13, H-14, H-15, H-16, H-17, H-18, H-19, H-20, H-21, H-22, H-23, and H-24. These 19 heaters are pooled together and regulated as one source referred to as the "19-Heater" source. Also included in this discussion are the Coker heater (H-3901) and the GOHDS heaters (H-8401 and H-8402).

The existing 19 heaters have a "bubbled" SO_2 permit emission limit of 30.0 tons per year (TPY) (164 lb/day) and a limitation of fuel gas H_2S content of 160 parts per million by volume (ppmv) (0.1 grains per dry standard cubic foot (gr/dscf)). With both these limitations intact, all of these heaters cannot simultaneously operate at their maximum design firing rates. This can cause un-optimized operation of the Refinery during unfavorable climatical conditions or during peak heater demand periods.

To allow all 19 heaters to simultaneously operate at their maximum firing rates, the allowable short term SO_2 emission limit for the "bubbled" 19 heaters must be increased. The (19) Refinery Fuel Gas Heaters/Furnaces lb/day SO_2 emission limitation was based on MMBtu/hr from the emission inventory database (AFS), and higher fuel heat value (1,015 British thermal units per standard cubic foot (Btu/scf)) from the 1990 Base-Year Carbon Monoxide Emission Inventory. By using these parameters, the daily "bubble" SO_2 permit limit can be raised to 386 lb/day, as was indicated in the Preliminary Determination. Conoco requested the daily limit be increased to 612 lb/day, which is equivalent to the rate used in the Billings SO_2 State Implementation Plan (SIP) modeling (111.7 TPY). The annual "bubble" SO_2 limit of 30.0 TPY was maintained.

The Department received comments from Conoco, in which Conoco contends that the maximum heat input (MMBtu/hr) from the AFS does not accurately reflect the real maximum firing rates of the heaters. After further review of the files, the Department established the total maximum firing rate for the (19) Refinery Fuel Gas Heaters/Furnaces to be 785.5 MMBtu/hr. This total maximum firing rate was identified by Conoco during the permit review of the Coker permit (MAQP #2619). The maximum heat input of 785.5 MMBtu/hr and the fuel heat of 958 Btu/scf are used to calculate a new daily "bubble" SO_2 permit limit of 529.17 lb/day.

The change in air emissions of other criteria pollutants (carbon monoxide (CO), nitrogen oxide (NO_X), particulate matter (PM), and VOC) associated with this project are zero, since the Potentials to Emit (PTE) were not changed. With the current 164-lb/day SO_2 limit, simultaneous maximum firing of these heaters can be accomplished if the fuel gas H_2S content stays below 49.75 ppmv. Conoco's amine systems produce fuel gas averaging (on an annual basis) of about 25 ppmv H_2S content or less (see 1993 and 1994 Refinery EIS's). Since the emissions of CO, NO_X, and VOC produced are not a function of H_2S content, and Conoco's current amine system can generate appropriate fuel gas to stay at or below the 164 lb/day SO_2 limit, the maximum potentials of these pollutants are obtainable and were not affected by this project. The PM limits for these heaters are 80 times higher than the amount generated by fuel gas combustion devices (see ARM 17.8.340); therefore, the PM emissions potential was not affected as well.

Even though Conoco's past annual average fuel gas H_2S content was below 37.8 ppmv, there was still potential to run into operational limitations in peak fuel gas demand periods. The amine systems may not be able to keep the fuel gas H_2S under 49.75 ppmv, rendering the refinery to operate at un-optimized rates. This was the reason for the request to raise the daily SO_2 emissions limit for the "19-Heater" source.

Since the proposed change to the heaters' SO_2 emissions limit does not reflect an annual increase in PTE, the project is not subject to PSD permitting review (threshold for SO_2 is 40 TPY).

In light of the SO_2 problem in the Billings-Laurel air shed, any change resulting in an increase of SO_2 emissions must have its impact determined to see if any National Ambient Air Quality Standards (NAAQS) will be violated as a result of the project. SO_2 modeling was completed by the Department to develop a revised SO_2 SIP for the Billings-Laurel area (see the Billings/Laurel SO_2 SIP Compliance Demonstration Report dated November 15, 1994). The "19-Heater source" was modeled using an SO_2 emission rate equivalent to 111.7 TPY to determine its SO_2 impact on the Billings-Laurel air shed. The results of this modeling showed there were no exceedances of the SO_2 NAAQS or the Montana standards resulting from its operation. Therefore, an increase in the permit limit from 164 lb/day to 612 lb/day of SO_2 did not result in any violations of SO_2 NAAQS or Montana standards; however, the daily emission limit set based on the NSPS limit of 0.1 grains per dry standard cubic foot (gr/dscf) (160 ppmv H_2S) is more restrictive than the SIP limit. The daily emission limit, based on NSPS, is 529.17 lb/day for the existing 19 heaters/furnaces.

With the change of a daily SO_2 permit limit for the "19-Heater" source, Conoco also requested that the "19-Heater" source, the Coker heater (H-3901), and the GOHDS heaters (H-8401 and H-8402) be combined into one permitted source called the "Fuel-Gas-Heaters" source. Using the existing daily SO_2 permit limits for the Coker heater and GOHDS heaters, an overall SO_2 emissions limit "bubble" of 614 lb/day would apply to the "22-Fuel-Gas-Heaters" source. The annual limit for the "22-Fuel-Gas-Heaters" source has not changed and is 45.50 TPY (30.00 + 9.60 + 2.90 + 3.00).

On April 19, 1997, Conoco was issued **MAQP #2619-09** to "bubble" or combine the allowable hourly and annual NO_X emission limits for the Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heaters. The NO_X emission limits for these heaters were established on a pounds-per-million-Btu basis, and will be maintained.

By "bubbling" or combining the allowable hourly and annual NO_X emission limits for the Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heaters allows Conoco more operational flexibility with regard to heater firing rates and heater optimization. The Coker heater still has an hourly NO_X emission limit to prevent any significant impacts. This permit alteration does not allow an increase in the annual NO_X emissions. MAQP #2619-09 replaced MAQP #2619-08.

On July 30, 1997, **MAQP #2619-10** was issued to Conoco in order to comply with 40 CFR 63, Subpart R, National Emission Standards for Gasoline Distribution Facilities. Conoco installed a gasoline vapor collection system and enclosed flare for the reduction of Hazardous Air Pollutants (HAPs) resulting from the loading of gasoline. The vapor combustion unit (VCU) was added to the bulk gasoline and distillate loading rack. The gasoline vapors were collected from the trucks during loading, then routed to an enclosed flare, where combustion occurs. The project results in overall reductions in the amount of actual emissions of VOCs (94.8 TPY), with a slight increase in CO (2.1 TPY) and NO_X (0.8 TPY) emissions. The actual reduction in potential emissions of VOCs is 899.5 TPY, while CO increases to 19.7 TPY and NO_X increases to 7.9 TPY emissions.

In addition, Conoco requested an administrative change be made to Section II.F.5, which brought the permit requirements in alignment with the monitoring requirements specified by 40 CFR 60, Subpart QQQ, and 40 CFR 61, Subpart FF.

Because Conoco's Bulk gasoline and distillate loading tank VCU is defined as an incinerator under Montana Code Annotated (MCA) 75-2-215, a determination that the emissions from the VCU constitutes a negligible risk to public health is required prior to the issuance of a permit to the facility. Conoco and the Department identified the following HAPs from the flare, which were used in the health risk assessment. These constituents are typical components of gasoline.

1. Benzene
2. Ethyl Benzene
3. Hexane
4. Methyl Tert Butyl Ether
5. Toluene
6. Xylenes

The reference concentrations for Ethyl Benzene, Hexane, and Methyl Tert Butyl Ether were obtained from EPA's IRIS database. The risk information for the remaining HAPs is contained in the January 1992 CAPCOA Risk Assessment Guidelines. The model performed by Conoco for the HAPs identified above, demonstrate compliance with the negligible risk requirement. MAQP #2619-10 replaced MAQP #2619-09.

On December 10, 1997, Conoco requested a modification to allow the continuous incineration of a PB Merox Unit off-gas stream in the firebox of Heater #16. MAQP #2619-10 required the production of SO_2 from the sulfur containing compounds in the PB Merox Unit off-gas stream to be calculated and counted against the current SO_2 limitations applicable to the (22) Refinery Fuel Gas Heaters/Furnaces group. During a review of process piping and instrumentation diagrams, Conoco identified a PB Merox Unit off-gas stream incinerated in the firebox of Heater #16. A subsequent analysis of this off-gas stream revealed the presence of sulfur-containing compounds in low concentrations. The bulk of this low-pressure off-gas stream is nitrogen with some oxygen, hydrocarbons, and sulfur-containing compounds (disulfides, mercaptans). SO_2 produced from the continuous incineration of this stream has been calculated at approximately 1 TPY. This off-gas stream is piped from the top of the disulfide separator through a small knock-out drum and directly into the firebox of Heater #16.

Conoco proposed to sample the PB Merox Unit disulfide separator gas stream on a monthly basis to determine the total sulfur (ppmw) present. This analysis, combined with the off-gas stream flow rate, is used to calculate the production of SO_2. After a year of sampling time and with the approval of the Department, Conoco may propose to reduce the sampling frequency of the PB Merox disulfide separator off-gas stream to once per quarter if the variability in the sulfur content is small (250 ppmw).

In addition, to be consistent with the wording as specified by 40 CFR 63, Subpart R, the Department replaced all references to "tank trucks" with "cargo tank" and all references to "truck loading rack" with "loading rack". Also, the first sentence in Section II.F.5 was deleted from the permit. Conoco had requested an administrative change be made to Section II.F.5, during the permitting action of #2619-10, which would bring the permit requirements in alignment with the monitoring requirements specified by 40 CFR 60, Subpart QQQ, and 40 CFR 61, Subpart FF. The Department approved the request and the correction was made, but the first sentence was inadvertently left in the permit. **MAQP #2619-11** replaced MAQP #2619-10.

On June 6, 2000, the Department issued **MAQP #2619-12** for replacement of the B-101 thermal reactor at the Jupiter Sulphur facility. The existing B-101 thermal reactor had come to the end of its useful life and had to be replaced. The replacement B-101 thermal reactor was physically located approximately 50 feet to the north of the existing thermal reactor, due to the excessive complications that would be encountered to dismantle the old equipment and construct the new equipment in the same space. Once the piping was rerouted to the new equipment the old equipment was incapable of use and will be demolished. Given this construction scenario, the Department determined that a permit condition limiting the operation to only one thermal reactor at a time was necessary. There was no increase in emissions due to this action. MAQP #2619-12 replaced MAQP #2619-11.

Conoco submitted comments on the Preliminary Determination (PD) of MAQP #2619-12. The following is the result of these comments:

> In previously issued permits, Section II.A.4 listed storage tanks #4510 and #4511 as having external floating roofs with primary seal, which were liquid mounted stainless steel shoes and secondary seal equipped with a Teflon curtain or equivalent. Conoco stated that these two tanks were actually equipped with internal floating roofs with double-rim seals or a liquid-mounted seal system for VOC loss control.
>
> Section II.A.7.g.ii always listed the CPI separators as primary separators, when in fact they are secondary.

The Department accepted the comments and made the changes, accordingly, in the Department decision version of the permit.

On March 1, 2001, the Department issued **MAQP #2619-13** for the installation and operation of 19 diesel-powered, temporary generators. These generators are necessary because of the high cost of electricity and supplement 18 MW of the refinery's electrical load, and 1 MW of Jupiter's electrical load. The generators are located south of the coke loading facility along with two new aboveground 20,000-gallon diesel storage tanks. The operation of the generators will not occur beyond 2 years and is not expected to last for an extended period of time, but rather only for the length of time necessary for Conoco to acquire a permanent, more economical supply of power.

Because these generators are only to be used when commercial power is too expensive to obtain, the amount of emissions expected during the actual operation of these generators is minor. In addition, the installation of these generators qualified as a "temporary source" under the PSD permitting program because the permit limited the operation of these generators to a time period of less than 2 years.

Therefore, Conoco was not required to comply with ARM 17.8.804, 17.8 820, 17.8.822, and 17.8.824. Even though the portable generators were considered temporary, the Department required compliance with Best Available Control Technology (BACT) and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 was ensured. In addition, Conoco is responsible for complying with all applicable ambient air quality standards. MAQP #2619-13 replaced MAQP #2619-12.

On April 13, 2001, the Department issued **MAQP #2619-14** for the 1982 Saturate Gas Plant Project, submitted by Conoco as a retroactive permit application. During an independent compliance awareness review that was performed in 2000, Conoco discovered that the Saturate Gas Plant should have gone through the permitting process prior to it being constructed. At the time of construction, the project likely would have required a PSD permit. However, the current PTE for the project facility is well below the PSD VOC significance threshold. In addition, the Saturate Gas Plant currently participates in a federally-required leak detection and repair (LDAR) program, which would meet any BACT requirements, if PSD applied. The Department agreed that a permitting action in the form of a preconstruction permit application for the Saturate Gas Plant Project was necessary and sufficient to address the discrepancy. MAQP #2619-14 replaced MAQP #2619-13.

On June 29, 2002, the Department issued **MAQP #2619-15** to clarify language regarding the Appendix F Quality Assurance requirements for the fuel gas H_2S measurement system and to include certain limits and standards associated with the Consent Decree lodged on December 20, 2001, respectively. In addition, the Department modified the permit to eliminate references to the now repealed odor rule (ARM 17.8.315), to correct the reference on conditions improperly referencing the incinerator rule (ARM 17.8.316), and to eliminate the limits on the main boiler that were less stringent than the current limit established by the Consent Decree. MAQP #2619-15 replaced MAQP #2619-14.

The Department received a request from Conoco on August 27, 2002, for the alteration of air quality MAQP #2619-15 to incorporate the Low Sulfur Gasoline (LSG) Project into the refinery's equipment and operations. The LSG Project was being proposed to assist in complying with EPA's Tier 2 regulations. The project included the installation of a new storage vessel and minor modifications to the No.2 hydrodesulfurization (HDS) unit, GOHDS unit, and hydrogen (H_2) unit in order to accommodate hydrotreating additional gasoline and gas oil streams that were currently not hydrotreated prior to being blended or processed in the FCCU. The new storage vessel was designed to store offspec gasoline during occasions when the GOHDS unit was offline.

In addition, on August 28, 2002, Conoco requested to eliminate the footnote contained in Section II.B.1.b of MAQP #2619-15 stating, "Emissions [of the SRU Flare] occur only during times that the ATS unit is not operating." Further, Conoco requested to change the SO_2 emission limitations of 25 pounds per hour (lbs/hr) for each of the SRU Flare and SRU/ATS Main Stack to a 25-lbs/hr limit on the combination of the SRU Flare and SRU/ATS Main Stack. Following discussion between Conoco and the Department regarding comments received within the Department and from EPA, Conoco requested an extension to delay issuance of the

Department Decision to December 9, 2002. Following additional discussion, Conoco and the Department agreed to leave the footnote in the permit for the issuance of **MAQP #2619-16** and to revisit the issue at another time. MAQP #2619-16 replaced MAQP #2619-15.

A letter from ConocoPhillips dated December 9, 2002, and received by the Department on December 10, 2002, notified the Department that Conoco had changed its name to ConocoPhillips. In a letter dated February 3, 2003, ConocoPhillips also requested the removal of the conditions regarding the temporary power generators because the permit terms for the temporary generators were "not to exceed 2 years" and the generators had been removed from the facility. The permit action changed the name on this permit from Conoco to ConocoPhillips and removed permit terms regarding temporary generators. **MAQP #2619-17** was also updated to reflect current permit language and rule references used by the Department. MAQP #2619-17 replaced MAQP #2619-16.

On December 11, 2003, the Department received a MAQP Application from ConocoPhillips to modify MAQP #2619-17 to replace the existing 143.8-MMBtu/hr boilers, B-5 and B-6, with new 183-MMBtu/hr boilers equipped with low NO_X burners (LNB) and flue gas recirculation (FGR) commonly referred to as ultra-low NO_X burners (ULNB), new B-5 and new B-6 (previously referred to as B-7 and B-8), to meet the NO_X emission reduction requirements stipulated in the EPA Consent Decree. On December 23, 2003, the Department deemed the application complete. This permitting action contained NO_X emissions that exceed PSD significance levels. The replacement of the boilers resulted in an actual NO_X reduction of approximately 89 tons per year. However, the EPA Consent Decree stipulated that reductions were not creditable for PSD purposes. MAQP #2619 was also updated to reflect current permit language and rule references used by the Department. **MAQP #2619-18** replaced MAQP #2619-17.

On February 3, 2004, the Department received a MAQP Application from ConocoPhillips to modify MAQP #2619-18 to add a new HDS Unit (No.5), a new sour water stripper (No.3 Sour Water Stripper (SWS)), and a new H_2 Unit. On March 1, 2004, the Department deemed the application complete upon submittal of additional information. The addition of these new units added three new heaters, 41, 42, and 43, each equipped with low LNB FGR commonly referred to as ULNB. Additionally, ConocoPhillips proposed to retrofit existing external floating roof tank T-110 with a cover to allow nitrogen blanketing of the tank, to install a new storage vessel (No.5 HDS Feed storage tank) under emission point 24 above, to store feed and off-specification material for the No.5 HDS Unit, and to provide the No.1 H_2 Unit with the flexibility to burn refinery fuel gas (RFG). The new equipment was added to meet the new EPA-required highway Ultra Low Sulfur Diesel (ULSD) fuel sulfur standard of 100% of highway diesel that meets the 15 parts per million (ppm) highway diesel fuel maximum sulfur specification by June 1, 2006. By meeting the June 1, 2006, deadline, ConocoPhillips may claim a 2-year extension for the phase in of the requirements of the Tier Two Gasoline/Sulfur Rulemaking. This permitting action resulted in NO_X and VOC emissions that exceed PSD significance levels. Other changes were also contained in this permit. Previously in permit condition II.A.1 it was stated that the emergency flare tip must be based at 148-feet elevation. After a physical survey of the emergency flare it was determined that the actual height of the flare tip is 141.5-feet elevation. After verifying that the impacts of the height discrepancy were negligible, the Department changed permit condition II.A.1 from 148-feet of elevation to 142-feet plus or minus 2 feet of elevation and changed the reference from ARM 17.8.752 to ARM 17.8.749. **MAQP #2619-19** was updated to reflect current permit language and rule references used by the Department. MAQP #2619-19 replaced MAQP #2619-18.

On June 15, 2004, the Department received an Administrative Amendment request from ConocoPhillips to modify MAQP #2619-19 to correct the averaging time for equipment subject to the 0.073 gr/dscf H_2S content of fuel gas burned limit. The averaging time was corrected from a rolling 3-hour time period to a rolling 12-month time period. The heaters subject to the 0.073 gr/dscf limit per rolling 12-month time period are subject to the Standards of Performance for NSPS, Subpart J limit of 0.10 gr/dscf per rolling 3-hour time period. **MAQP #2619-20** replaced MAQP #2619-19.

On March 15, 2005, the Department received a complete MAQP Application from ConocoPhillips to modify MAQP #2619-20 to update the HDS Unit (No.5), sour water stripper (No.3 SWS), and H_2 Unit added in ULSD MAQP Modification #2619-19. Due to the final project design and vendor specifications, and further review of the EPA compiled emission factor data, the facility's emission generating activities, and MAQP #2619-19, ConocoPhillips proposed the following changes:

1. Deaerator Vent (44) at the No.2 H_2 Unit is to be deleted

2. No.2 H_2 Unit PSA Offgas Vent (45) is to be added

3. CO emission factors for the three new heaters to be changed from AP-42 Section 1.4 (October 1996) to vendor guaranteed emission factors

4. Particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) exhaust emission factors for the combustion of PSA vent gas in the No.1 H_2 Heater and the No.2 H_2 Reformer Heater to be changed from AFSCF, EPA 450/4-90-003 p.23 to AP-42, Section 1.4 (July 1998)

5. The dimensions, secondary rim seal, and specific deck fittings data for the No.5 HDS Feed Tank to be updated. The tank is proposed to store material with a maximum true vapor pressure of 11.1 pounds per square inch at atmosphere (psia).

6. Specific deck fittings for existing Tank-110 to be revised. The tank is proposed to store material with a maximum true vapor pressure of 11.1 psia.

7. The existing No.1 H_2 Unit PSA Offgas Vent (46) to be added to the permit. This unit is not affected by the ULSD project, but is included with this submittal as a reconciliation issue.

8. The NO_X emissions limitations cited for each of the three new ULSD Project heaters are requested to be clarified as "per rolling 12-month time period."

9. The CO emissions limitations cited for each of the three new ULSD Project heaters be replaced and cited with the appropriate updated values and associated averaging periods.

10. The nomenclature for Boilers B-7 and B-8 be changed to new B-5 and new B-6 respectively.

11. In accordance with Paragraph 54 of the Consent Decree the FCCU became subject to the SO_2 portions of Standards of Performance for New Stationary Sources (NSPS), Subpart J on February 1, 2005.

12. 40 CFR 63, Subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters) has been finalized. The regulatory applicability analysis has been updated for the three new heaters.

MAQP #2619-21 replaced MAQP #2619-20.

On January 15, 2007, the Department received a complete application which included the request to incorporate the following permit conditions, which were requested in separate letters:

- Refinery Main Plant Relief Flare – to clarify that the flare is subject to NSPS 40 CFR 60, Subparts A and J (as requested September 28, 2004)

- FCCU – to clarify that the FCCU is subject to CO and SO_2 portions of Subpart J (requested September 26, 2003, and February 8, 2005, respectively, and partly addressed in MAQP #2619-21)

- FCCU - to clarify that the FCCU was subject to an SO_2 emission limit of 25 parts per million, on a volume, dry basis (ppmvd), corrected to 0% oxygen (O_2), on a rolling 365-day basis, and subject to an SO_2 emission limit of 50 ppmvd, corrected to 0% O_2, on a rolling 7-day basis, and clarify the 7-day SO_2 50 ppmvd emission limit established for the FCCU shall not apply during periods of hydrotreater outages (requested February 1, 2006)

- Temporary Boiler Installation – to allow the installation and operation, for up to 8 weeks per year, of a temporary natural gas-fired boiler not to exceed 51 MMBtu/hr, as requested January 4, 2007

The permit was also updated to reflect the current style that the Department issues permits. **MAQP #2619-22** replaced MAQP #2619-21.

The Department received two requests from ConocoPhillips for modifications to the permit in conformance with requirements contained in their Consent Decree (Civil Action #H-01-4430):

- 5/31/07 – request to clarify that the Jupiter Sulfur Plant Flare (Jupiter Flare) is subject to 40 CFR 60, Subparts A and J; and

- 8/29/07 – request to clarify that the FCCU is subject to a PM emission limit of 1 lb per 1,000 lb of coke burned, and that it is an affected facility subject to 40 CFR 60, Subparts A and J, including the 30% opacity limitation. The requirement to maintain less than 20% opacity was then removed, since the FCCU became subject to the 30% Subpart J opacity limit which supersedes the ARM 17.8.304 opacity limit.

The Department amended the permit, as requested. In addition, the references to 40 CFR 63, Subpart DDDDD were changed to reflect that this regulation has become "state-only" since, although the federal rule was vacated on July 30, 2007, this MACT was incorporated by reference in ARM 17.8.342. Lastly, reference to Tank T-4524 was corrected to T-4523 (wastewater surge tank) and regulatory applicability changed from 40 CFR 60, Subpart Kb to Subpart QQQ, and the LSG tank identification was corrected to T-2909. **MAQP #2619-23** replaced MAQP #2619-22.

On August 21, 2008, the Department received a complete NSR-PSD permit application from ConocoPhillips. ConocoPhillips is proposing to replace the existing Small and Large Crude Units and the existing Vacuum Unit with a new, more efficient Crude and Vacuum Unit. This project is referred to as the New Crude and Vacuum Unit (NCVU) project. The NCVU project will enable ConocoPhillips' Billings refinery to process both conventional crude oils and SynBit/oil sands crude oils and increase crude distillation capacity about 25%. The NCVU project will require modifications and optimization of the following existing process units: No. 2 HDS Unit, Saturate Gas Plant, No. 2 and No. 3 Amine Units, No. 5 HDS Unit, Coker Unit, No. 1 and 2 H_2 Plants, Hydrogen Purification Unit (HPU), Raw Water Demineralizer System, Jupiter SRU/ATS Plant, and the FCCU. The primary objectives of the NCVU Project are to improve crude fractionation and energy efficiency of the refinery, and to increase crude processing capacity and crude feed flexibility to reduce feed costs. As a result of the NCVU Project, the Jupiter Plant feed rate capacity will need to be increased to approximately 235 LTD of sulfur. With the submittal of this complete application, the minor source baseline dates for SO_2, PM, and PM_{10} have now been triggered in the Billings area as of August 21, 2008. The minor source baseline date for NO_x was already established by Yellowstone Energy Limited Partnership (formerly Billings Generation Inc.) on November 8, 1991.

In addition, the Department clarified the permit language for the bulk loading rack VCU regarding the products that may be loaded in the event the VCU is inoperable. **MAQP #2619-24** replaced MAQP #2619-23.

On June 12, 2009, the Department received a request from ConocoPhillips to administratively amend MAQP #2619-24 to include certain limits and standards. This amendment was in response to requirements contained in the Consent Decree (CD) that ConocoPhillips has entered into with EPA along with the Department. The CD was set forth on December 20, 2001.

As a result of the requirements set forth within the CD, ConocoPhillips had requested the following limits and standards (agreed to by EPA) to be included in the MAQP:

The NO_x emissions from the FCCU shall have a limit of 49.2 parts per million, volumetric dry (ppmvd), corrected to 0% O_2, on a rolling 365-day average and 69.5 ppmvd, corrected to 0% O_2, on a rolling 7-day average. Per Paragraph 27 of the above-referenced CD, the 7-day NO_x emission limit established for the FCC shall not apply during periods of hydrotreater outages at the refinery, provided that ConocoPhillips is maintaining and operating its FCC (including associated air pollution control equipment) in a manner consistent with good air pollution control practices for minimizing emissions in accordance with the EPA-approved good air pollution control practices plan.

As a result of this request, **MAQP #2619-25** replaced MAQP #2619-24.

On December 6, 2010, the Department received a request from ConocoPhillips to administratively amend MAQP #2619-25 to include certain limits, standards, and obligations in response to agency requests and the requirements of Paragraph 210(a) contained the ConocoPhillips CD. ConocoPhillips also requested to include conditions pertaining to facility-related Supplemental Environmental Projects (SEP), although not specifically required by the ConocoPhillips CD. ConocoPhillips later rescinded the request to include these SEP conditions within this permit action. ConocoPhillips additionally requested removal of references to Tank #162 (Ground Water Interceptor System (GWIS) Recovered Oil Tank) as this tank has been taken out of service. With knowledge of forthcoming additional information and administrative amendment requests, in concurrence with ConocoPhillips, the Department withheld preparation and issuance of a revised MAQP; however, this action was assigned MAQP #2619-26.

On July 28, 2011, the Department received a request from ConocoPhillips to administratively amend MAQP #2619-25 to include the following language (underlined):

> NO_x emissions shall not exceed 49.2 ppmvd corrected to 0% O_2, on a rolling 365-day average and 69.5 ppmvd, corrected to 0% O_2, on a rolling 7-day average. The 7-day NO_x emission limit shall not apply during periods of hydrotreater outages, provided that ConocoPhillips is maintaining and operating the FCCU (including associated air pollution control equipment) consistent with good air pollutions control practices for minimizing emissions in accordance with the EPA-approved good air pollution control practices plan. For days in which the FCCU is not operating, no NOx value shall be used in the average, and those periods shall be skipped in determining the 7-day and 365-day averages (ConocoPhillips Consent Decree, Paragraph 27, as amended).

ConocoPhillips requested this addition in language as a result of an April 29, 2011 letter from EPA, which contained the formal approval of the FCC NOx emission limits required by the CD. The letter included EPA's expectations as to how these NOx emission concentration averages are to be calculated.

This amendment to MAQP #2619-25 included the requested changes from the December 6, 2010, and July 28, 2011, administrative amendment requests.

As a result of both of these requests, **MAQP #2619-27** replaced MAQP #2619-25.

On September 13, 2011, October 7, 2011, October 25, 2011, and October 31, 2011, the Department received elements to fulfill a complete air quality permit application from ConocoPhillips. ConocoPhillips requested a modification to their existing air quality permit to incorporate conditions and limitations associated with the proposed installation of a Backup Coke Crusher. A Backup Coke Crusher is necessary to ensure crushed coke is available at all times for the facility, particularly during instances when the main Coke Crusher is not operational as a result of mechanical failure and/or maintenance activities. The components of the Backup Coke Crusher include the coke crushing unit as well as a diesel fired engine and compressor.

This permit action incorporated all limitations and conditions associated with the proposed Backup Coke Crusher. **MAQP #2619-28** replaced MAQP #2619-27.

On May 3, 2012, the Department received a request to administratively amend MAQP #2619-28 to incorporate a change in the ConocoPhillips Company name. On May 1, 2012, the downstream portions of the ConocoPhillips Company were spun-off as a separate company named Phillips 66 Company (Phillips 66). As a result of the spin-off, the former ConocoPhillips Billings Refinery is now the Phillips 66 Billings Refinery. The permit action incorporated the name change throughout, and **MAQP #2619-29** replaced MAQP #2619-28

On October 9, 2012, the Department received an Administrative Amendment Request to delete conditions regarding the New Crude and Vacuum Unit because the project was cancelled, clarification of various rule applicabilities and other minor edits. A letter outlining the requested changes in bullet point fashion is on file with the Department. **MAQP #2619-30** replaced MAQP #2619-29.

On May 1, 2014, the Department received an Administrative Amendment request from Phillips 66. Phillips 66 is in the process of taking steps to close out the Consent Decree with the Environmental Protection Agency (EPA) and the State of Montana. Phillips 66 requested that limits and standards from the Consent Decree which are required to live on beyond the life of the Consent Decree be present in the permit, with authority for those conditions to rest outside of regulatory reference to the Consent Decree itself. The action removed references to the Consent Decree as a regulatory basis. The changes taking place in this action are tabelized below. Following the first table is a table which contains additional information regarding all conditions in the MAQP which are believed to have originated through the Consent Decree. **MAQP #2619-31** replaced MAQP #2619-30.

MAQP #2619-31 Table 1: Changes taking place in this action

MAQP #2619-30 Condition	Source	Pollutant	Obligation	CD Paragraph	Prior Permit Reference	New Regulatory Reference
II.E.5.c.i	Boiler Stack	SO_2	CEMS	71	CD	17.8.749
II.C.1.d.ii	FCC	SO_2	7-day & 365-day limits	40	CD	17.8.749
II.C.1.d.vi	FCC	NOx	7-day & 365-day limits	17	CD	17.8.749
II.C.1.d.iv	FCC	CO	365-day limit	50	CD	17.8.749

MAQP #2619-30 Condition	Source	Pollutant	Obligation	CD Paragraph	Prior Permit Reference	New Regulatory Reference
II.C.1.d.v	FCC	CO	1-hr limit	49	CD	17.8.749
II.C.1.d.vii	FCC	PM	1 lb/1000 lb coke burn	46, 47(a)	CD	17.8.749
II.A.1.c.v	FCC	----	NSPS J and A applicability	54	CD	17.8.749
II.C.1.d.iii	FCC	SO_2	NSPS J limit	54	CD	17.8.749
II.C.1.d.vii	FCC	PM	NSPS J limit	54	CD	17.8.749
II.C.1.d.viii	FCC	Opacity	NSPS J limit	54	CD	17.8.749
II.E.5.b.v	FCC	NOx	CEMS	28	CD	17.8.749
II.E.5.b.iv	FCC	CO	CEMS	49	CD	17.8.749
II.E.5.b.vi	FCC	O_2	CEMS	28, 37	CD	17.8.749
II.E.5.b.i	FCC	SO_2	CEMS	37	CD	17.8.749
II.E.5.b.iii	FCC	Opacity	COMS	47(b)	CD	17.8.749
II.E.4	FCC	PM	Particulate Emissions Test-annual	47(a)	CD	17.8.749
II.B.1	Flare-Refinery	SO_2	RCFAs & FGRS	162	CD	17.8.749
II.A.1.c.iii	Flare-Refinery	SO_2	NSPS J and A applicability	161	CD	17.8.749
II.A.1.c.iv	Flare-Jupiter	SO_2	NSPS J and A applicability	155	CD	17.8.749
II.A.1.c.i	Heaters/Boilers	SO_2	NSPS J applicability	69	none	17.8.749
II.C.1.e.i	Heaters	SO_2	No fuel oil burning	**	none	17.8.749
II.C.1.e.iii	Heaters	SO_2	Limit of 0.10 gr/dscf H_2S in fuel gas	69	none	17.8.749
II.C.1.f.iv	Boilers	SO_2	Limit of 0.10 gr/dscf H_2S in fuel gas	69	none	17.8.749
II.C.1.f.ii	Boilers	SO_2	300 ton/365-day rolling avg.***	71	CD	17.8.749
absent	Flare-Jupiter	SO_2	RCFAs for NSPS J	179	none	17.8.749

*** Condition existed in MAQP prior to Consent Decree
** Not in Consent Decree but requested as part of this action

MAQP #2619-31 Table 2: All conditions originating from Consent Decree

Source	CD Limit or Obligation	MAQP #2619-30 Permit Condition	Compliance Demonstration
FCCU	365-Day Rolling Average NO_x Emission =49.2 ppmvd @ 0% O_2 7-Day Rolling Average NOx Emission = 69.5 ppmvd @ 0% O_2 Hydrotreater Outages (7-Day Limit Shall Not Apply)	Sec. II.C.1.d.vi	Sec. II.E.5.b.v Sec. II.E.b.vi Sec. II.E.7 Sec. II.E.8
FCCU	365-Day Rolling Average SO_2 Emission = 25 ppmvd @ 0% O_2 7-Day Rolling Average SO_2 Emission = 50 ppmvd @ 0% O_2 Hydrotreater Outages (7-Day Limit Shall Not Apply)	Sec. II.C.1.d.ii	Sec. II.E.5.b.i Sec. II.E.b.vi Sec. II.E.7
FCCU	PM Emission = 1 lb/1000 lbs coke burned	Sec. II.C.1.d.vii	Sec. II.E.4
FCCU	1-Hour Average CO Emission = 500 ppmvd @ 0% O_2 (Startup, Shutdown, or Malfunctions not used in determining compliance with this limit. - 2nd Amendment) 365-Day Rolling Average CO Emission = 150 ppmvd @ 0% O_2	Sec. II.C.1.d.v Sec. II.C.1.d.iv	Sec.II.E.5.b.iv Sec. II.E.7
FCCU	Must comply with NSPS Subpart A and J - SO_2	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec. II.C.1.d.iii *(Emission Limit)*	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec.II.E.5.b.i *(Emission Monitoring)* Sec. II.E.7 *(Emission Monitoring)*
FCCU	Must comply with NSPS Subpart A and J - PM	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec. II.C.1.d.vii *(CD Emission Limit)*	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec.II.E.4 *(Emission Testing)*

Source	CD Limit or Obligation	MAQP #2619-30 Permit Condition	Compliance Demonstration
FCCU	Must comply with NSPS Subpart A and J - CO	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec. II.C.1.d.v *(CD Emission Limit)*	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec.II.E.5.b.iv *(Emission Monitoring)* Sec. II.E.7 *(Emission Monitoring)*
FCCU	Must comply with NSPS Subpart A and J - Opacity	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec. II.C.1.d.viii *(Emission Limit)*	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec.II.E.5.b.iii *(Emission Monitoring)* Sec. II.E.7 *(Emission Monitoring)*
Boilers	Must comply with NSPS Subpart J (SO_2, CO & PM) 365-Day Rolling Average SO_2 Emissions = 300 tpy (Fuel-Oil Burning Only)	Sec. II.A.1.c.i *(General Condition)* Sec. II.C.1.f.ii *(Emmission Limit)* Sec. II.C.1.f.iii *(Emission Limit)*	Sec. II.A.1.c.i *(General Condition)* Sec. II.E.5.c.i *(Emission Monitoring)* Sec. II.E.7 *(Emission Monitoring)* Sec. II.E.5.e *(Emission Monitoring)*
Heaters	Must comply with NSPS Subpart J (SO_2, CO & PM) 365-Day Rolling Average SO_2 Emissions = 300 tpy (Fuel-Oil Burning Only)	Sec. II.A.1.c.i *(General Condition)* Sec. II.C.1.e.i *(Operating Condition)* Sec. II.C.1.f.iii *(Emission Limit)*	Sec. II.E.5.e *(Emission Monitoring)*
SRU/Ammonium Sulfide Unit Flare (Jupiter Flare)	Must comply with NSPS Subpart A and J.	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.iv *(General Condition)* Sec. II.C.7 *(Operating Condition)*	Sec. II.E.5.f

Source	CD Limit or Obligation	MAQP #2619-30 Permit Condition	Compliance Demonstration
Main Plant Flare (Refinery)	Must comply with NSPS Subpart A and J.	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.iii *(General Condition)* Sec. II.B.1 *(Control Requirement)* Sec. II.C.6.a *(Operating Condition)*	Sec. II.E.5.f
Jupiter SRU/ATS Main Stack	Must comply with NSPS Subpart A and J.	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.ii *(General Condition)*	
Main Plant Flare (Refinery)	Root Cause Failure Analysis	Sec. II.C.6	

D. Current Permit Action

On September 16, 2014, the Department received an application from Phillips 66 to propose physical and operational changes to process units and auxiliary facilities at the refinery in order to provide more optimized operations for a broader spectrum of crude oil slates. This application was assigned **MAQP #2619-32**. Changes are primarily related to certain crude distillation, hydrogen production and recovery, fuel gas amine treatment, wastewater treatment, and sulfur recovery equipment and operations. A detailed list of project-affected equipment with a description of the changes proposed is presented below:

Summary of Project-Impacted Emissions Units			
Emissions Unit	**Type of Unit (Existing/New)**	**Maximum Capacity**	**Project Impact**
Small Crude Unit Heater, H-1	Existing	55.92 MMBtu/hr (HHV)	The tubes in the Small Crude Unit Heater, H-1 will be replaced with upgraded metallurgy tubes. Phillips 66 has not sought to treat this change as qualifying for one of the exemptions from what is a physical change or change in the method of operation under relevant PSD regulations.
Vacuum Furnace, H-17 – Existing Furnace	Existing	n/a	This emissions unit will be discontinued from service and replaced by a new process heater, as noted below.
Vacuum Furnace, H-17 – Replacement Furnace	New	75 MMBtu/hr (HHV)	This emissions unit will be constructed to replace the refinery's existing Vacuum Furnace, H-17, which, as noted above, will be removed from service.

Summary of Project-Impacted Emissions Units			
Emissions Unit	**Type of Unit (Existing/New)**	**Maximum Capacity**	**Project Impact**
FCCU Preheater, H-18	Existing	77 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project because the actual feed rate (and the gas oil content of the feedstock) to the No. 4 HDS Unit, which provides the feed to this heater, is anticipated to increase due to the project. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
Large Crude Unit Heater, H-24	Existing	108.36 MMBtu/hr (HHV)	This emissions unit will be physically modified, including the installation of upgraded metallurgy tubes to replace the existing tubes in the heater and the installation of ULNBs to replace the existing burners in the heater.
FCCU Stack	Existing	8,285.50 million barrels per year (gas oil feed)	Phillips 66 estimated that the project would result in an increase in the actual FCCU catalyst regenerator coke burn rate equal to approximately 12% of its annual average potential to emit coke burn rate. This coke burn rate increase will be associated with the actual increase in throughput and slightly heavier gas oil feedstock expected for the FCCU. The increase in throughput and gas oil feedstock density for the FCCU will occur because the No. 4 HDS Unit, which provides the feed to the FCCU, is estimated to experience an increase in the gas oil content of its feed, as well as an overall increase in its actual feed rate, as a result of the project. These changes to the No. 4 HDS Unit feed will occur because of the improved separation capabilities of the new Vacuum Unit Fractionator (W-57). The estimated increase in actual FCCU catalyst regenerator coke burn rate will make use of existing coke burn rate capacity that is not currently being utilized. The project does not propose to increase the coke burn rate capacity or the potential to emit emission rates of the FCCU catalyst regenerator.
Storage Tanks	Existing		Certain storage tanks at the refinery are anticipated to experience an increase in actual annual throughput primarily because of the improved straight run diesel and gas oil separation operations that will occur as a result of the project. This improvement in straight run diesel and gas oil separation will generally result in an increase in the throughput for diesel and gas oil storage tanks at the refinery. On the other hand, certain storage tanks at the refinery will experience a decrease in actual annual throughput as a result of the project. The refinery storage tanks expected to experience a decrease in throughput are those tanks that generally store lighter (higher vapor pressure) materials, such as gasoline and gasoline blendstocks. These actual throughput decreases have not been evaluated for PSD applicability determination purposes (*i.e.*, any emissions decreases that may result due to these throughput decreases have not been estimated because Phillips 66 does not intend to make such emissions decreases creditable). Additionally, the Coker Break Tanks (T-4512 and T-4513) at the refinery will be removed from service and replaced by two new API separator bays.

Summary of Project-Impacted Emissions Units			
Emissions Unit	**Type of Unit (Existing/New)**	**Maximum Capacity**	**Project Impact**
Fugitive VOC Emissions	Existing-New		New piping fugitive components (*e.g.*, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, and flanges or other connectors) are expected to be added to the refinery as a result of the project due to certain piping and equipment additions that will occur as part of the project. Also, new process drains and junction boxes are anticipated to be added to the refinery as part of the project. Furthermore, the Primary OWS (T-163) at the refinery will be removed from service and replaced by two new API separator bays.
CPI Separator Tanks	Existing		The OWSs (CPI OWSs (T-169 and T-170)) representing this emissions unit are planned to be removed from service and replaced by two new API separator bays.
No. 4 HDS Recycle Hydrogen Heater, H-8401	Existing	31.20 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project because the improved separation to be provided by the new Vacuum Unit Fractionator (W-57) will result in an increase in the actual feed rate to the No. 4 HDS Unit. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
No. 4 HDS Fractionator Feed Heater, H-8402	Existing	31.70 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project because the improved separation to be provided by the new Vacuum Unit Fractionator (W-57) will result in an increase in the actual feed rate to the No. 4 HDS Unit. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
No. 1 H_2 Unit Reformer Heater, H-9401	Existing	179.20 MMBtu/hr PSA Gas, HHV 76.80 MMBtu/hr Natural Gas/Cryo Gas, HHV	Modifications will be made to the burners in the No. 1 H_2 Unit Reformer Heater, H-9401 (EPN 35) to improve the flame pattern of these burners and to reduce hot spots on the tubes located in this heater. The type of burner modification may include changing the angle of the burners relative to this heater's tubes. Phillips 66 has not sought to treat this change as qualifying for one of the exemptions from what is a physical change or change in the method of operation under relevant PSD regulations.
Coke Handling	Existing		Based on engineering calculations, the actual annual coke production rate of the Coker Unit is expected to increase as a result of the project due to the heavier vacuum residuum that will be sent to the Coker Unit after the implementation of the project. Therefore, the actual annual amount of coke handled at the refinery is expected to increase as a result of the project.

Summary of Project-Impacted Emissions Units			
Emissions Unit	**Type of Unit (Existing/New)**	**Maximum Capacity**	**Project Impact**
No. 5 HDS Charge Heater, H-9501	Existing	25.0 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project primarily because the improved separation to be provided by the new Vacuum Unit Fractionator (W-57) will result in more diesel range material being routed to the No. 5 HDS Unit rather than the No. 4 HDS Unit. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
No. 5 HDS Stabilizer Reboiler Heater, H-9502	Existing	49.00 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project primarily because the improved separation to be provided by the new Vacuum Unit Fractionator (W-57) will result in more diesel range material being routed to the No. 5 HDS Unit rather than the No. 4 HDS Unit. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
No. 2 H_2 Unit Reformer Heater, H-9701	Existing	111.35 MMBtu/hr PSA Gas, HHV 79.65 MMBtu/hr Natural Gas/Cryo Gas, HHV	The actual feed rate to this process heater is anticipated to increase as a result of the project in order to provide a portion of the increase in hydrogen production expected to be required by the project. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 15% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
Coker Vent and Coke Cutting	Existing		Based on engineering calculations, the actual annual coke production rate of the Coker Unit is expected to increase as a result of the project due to the heavier vacuum residuum that will be sent to the Coker Unit after the implementation of the project. In association with this annual coke production rate increase is a decrease in coke drum cycle time. Therefore, the actual annual number of coke drum opening and coke cutting events is expected to increase as a result of the project.
Cooling Tower	New	7,000 gallons per minute	This cooling tower will be newly constructed to accommodate the increase in cooling water demand estimated to be required by the modified Vacuum Unit.
Railcar Clarified Oil Loading	Existing		The existing railcar clarified oil loading operation at the refinery is anticipated to experience an increase in annual throughput relative to the current annual throughput at which this operation typically operates due to the higher annual operating rate expected for the FCCU as a result of the project.

Summary of Project-Impacted Emissions Units			
Emissions Unit	**Type of Unit (Existing/New)**	**Maximum Capacity**	**Project Impact**
API Separator Tanks	New	132,058 thousand gallons per year	The OWSs representing this emissions unit will replace the following equipment currently located at the refinery: (1) Coker Break Tanks (T-4512 and T-4513); (2) Primary OWS (T-163); and (3) CPI OWSs (T-169 and T-170).
Jupiter Main Stack No. 1	Existing		SRU No. 1, which emits through this stack, will experience multiple physical changes to accommodate a portion of the increased amount of sulfur-containing compounds that will be routed to the Jupiter Plant as a result of the project.
Jupiter Main Stack No. 2	New		SRU No. 3, which will emit through this stack, will be newly constructed as part of the project to accommodate a portion of the increased amount of sulfur-containing compounds that will be routed to the Jupiter Plant as a result of the project.
Jupiter Cooling Tower, CT-602	New	7,000 gallons per minute	This cooling tower will be newly constructed to accommodate the increase in cooling water demand estimated to be required by the Jupiter Plant as a result of the project.
Jupiter Sulfur Storage Tanks	Existing-New		The two existing atmospheric sulfur storage tanks (V-117 and V-355) at the refinery may experience an increase in actual annual throughput due to improved sulfur recovery operations of the respective SRUs associated with these tanks and an increase in sulfur loading to the same respective SRUs. Additionally, a new atmospheric sulfur storage tank (V-370) is proposed to be installed at the refinery as part of the project.
Jupiter Railcar and Tank Truck Sulfur Loading	Existing-New		The existing railcar and tank truck sulfur loading arms at the refinery may experience an increase in actual annual throughput as a result of the project. Additionally, one new railcar sulfur loading arm and one new tank truck sulfur loading arm are planned to be installed at the refinery as part of the project.

E. Response to Public Comments (only if there are comments received)

Person /Group Commenting	Draft Permit Reference	Comment	Department Response
Randall Richert, Phillips 66 Company	To include on page 29 of the Draft Permit	Include the Railcar Clarified Oil Loading as an Emission Point, as discussed in the Vacuum Improvement Project application, Background Information section, page 4	The Department added the emissions point to the permit. This is an administrative change to the permit unrelated to this project, but was requested within this action within the application. The Railcar Clarified Oil Loading Emissions point has existed for a long time.
Randall Richert, Phillips 66 Company	Section II.J.1.a.1, II.J.2.a.1, II.J.3.a.2,	Please revise the long-term emission standard averaging period reference from "50 ppmv determined daily on a 365 successive calendar day rolling average basis" to "50 ppmv determined on a calendar year basis" in order for the averaging period for the	Upon further discussion between DEQ and Phillips 66, it was agreed that due to the form of the applicable NSPS standard, the averaging period as proposed does not pose an additional recordkeeping burden. The condition has remained as

Person /Group Commenting	Draft Permit Reference	Comment	Department Response
		standard to be consistent with emissions inventory requirements.	originally proposed in the Draft permit.
Randall Richert, Phillips 66 Company	Section II.J.1.a.2 II.J.3.a.3 II.J.4.a.2	Please delete "at 0% 0$_2$1 because this reference is not necessary. In reference to section II.J.1.a.2 and II.J.4.a.2: Please add "on a 30-day rolling average basis."	The reference to "at 0% O2" has been deleted. In reference to II.J.1.a.2 and II.J.4.a.2 averaging periods: A 30 day rolling average basis is potentially not an enforceable limitation for units in which no CEMS or other monitoring method to measure compliance on a 30 day rolling average basis was proposed as acceptable. However, the limitation is not intended to be interpreted as a limit which applies on an instantaneous basis, which is part of the basis of concern regarding this comment. The condition was clarified to infer that the limit is to be interpreted as measured by a source test conducted in adherence to the Montana Source Test Protocol and Procedures Manual. This is how this limit would have been interpreted without the clarification.
Randall Richert, Phillips 66 Company	Section II.J.1.a.7, II.J.2.a.7, II.J.3.a.8, II.J.4.a.6,	Please correct from 247,040 lb per calendar year to 254,040 lb per calendar year.	The correction was made as requested. This was an emissions limit applicable to the sum of emissions from all process heaters located at the refinery, and originated from the Billings/Laurel SO2 SIP. No change was necessary to these already existing limits.
Randall Richert, Phillips 66 Company	Section II.J.1.b.4, II.J.3.b.5	Please delete this maintenance recordkeeping requirement because it is vague, subject to misinterpretation, and has not been included in recently issued permits for similar sources.	The Department has determined that compliance with MACT DDDDD can suffice as BACT for VOC, and agrees the MACT outlines more practically enforceable conditions. Operating all equipment to provide the maximum air pollution control for which it was designed is a requirement of ARM 17.8.752, and is applicable.

Person /Group Commenting	Draft Permit Reference	Comment	Department Response
Randall Richert, Phillips 66 Company	Section II.J.2.a.3	For regulatory applicability correctness, please revise from "modified process heater" to "reconstructed process heater".	The language of the condition was updated to reflect that the unit will be considered reconstructed under NSPS.
Randall Richert, Phillips 66 Company	Section II.J.3.b.7	Please delete this requirement because it is a duplicate of Section II.J.3.a.8.	The condition has been deleted.
Randall Richert, Phillips 66 Company	Section II.J.4.b.1	Please revise from an every 5 year time period to as required by the Department	The permit was updated as requested as this approach was utilized in Section II.J.1 as well.
Randall Richert, Phillips 66 Company	Section II.J.5.a.14.c	Please correct from "16.70 tons per year" to "18.46 tons per year".	The permit was updated as requested.
Randall Richert, Phillips 66 Company	Section II.J.5.a.14.a-f	Please revise from "determined monthly on a rolling 12 month basis" to "determined on a calendar year basis"	The language provided in the draft provides for the maximum averaging period typically allowable for this type of limit.
Randall Richert, Phillips 66 Company	Section II.J.5.b.4-7	Please delete these reporting requirement because they are onerous and not believed to be warranted as part of this permitting action	The quarterly reports currently submitted to the Department contain SO_2, NO_X, and NH_3 information already. No change has been made.
Randall Richert, Phillips 66 Company	Section II.J.6	Please revise from "Piping Component Type Fugitive Emissions" to "Piping and Wastewater Component Type Fugitive Emissions"	The permit has been updated as requested.
Randall Richert, Phillips 66 Company	Section II.J.6.a.4	Please delete this requirement because it is an error. A new individual drain system will not be installed for the No. 4 HDS Unit	The condition has been deleted.
Randall Richert, Phillips 66 Company	Section II.J.7.a.1	Please revise the condition to read "The separator bays of the two new API separator Tanks shall be covered and sealed and the vapor from these bays shall be routed to a VOC control device to control VOC emissions with at least a 95% control efficiency"	Because PSD applicability calculations did not account for emissions from thermal oxidation, a carbon canister was prescribed as proposed in the application. However, the permit condition was updated slightly to clarify that it is through ARM 17.8.749 that the control technology must be carbon canister.
Randall Richert, Phillips 66 Company	Section II.J.7.a.5	Please revise the condition to read "Phillips 66 shall permanently remove from current service, the Coker Break Tanks (T-4512 and T4513), the Primary Oil Water Separator (T-163), and the CPI Oil Water Separator (T-169 and T-170). (ARM 17.8.749)"	The permit has been updated to insert the word 'current' into the permit condition language.

Person /Group Commenting	Draft Permit Reference	Comment	Department Response
Randall Richert, Phillips 66 Company	Section II.J.8.a.2 and b.2	Please delete these water conductivity requirements because they are onerous, not believed to be warranted for this size of a cooling tower, and were not idenftified in other refinery permits.	Although it is recognized that these cooling towers are small from an emissions standpoint, a conductivity must be assumed in order to calculate emissions, and PSD thresholds are being approached. Because water conductivity is monitored for process control reasons anyway, and with further discussion with Phillips 66, the conditions have remained as proposed, with addition of language indicated alternative monitoring methods may be approved by the Department.
Randall Richert, Phillips 66 Company	Section II.J.8.a.4 and II.J.9.a.4	Please correct the "40 CFR 60 Subpart Q" references to "40CFR 63 Subpart Q". In association with this change, plase correct the ARM reference to ARM 17.8.342. Please note that, per 40 CFR 63.400(a), this regulation will not apply if chromium –based water treatment chemicals are not used in the cooling tower. The facility plans to operate the cooling tower without chromium –based water treatment chemicals.	The permit was inadvertently referencing this MACT as an NSPS. Updates were made to recognize these requirements as a MACT.
Randall Richert, Phillips 66 Company	Section II.J.9.a.2 and b.2	Please delete these water conductivity requirements because they are onerous, not believed to be warranted for this size of a cooling tower, and were not idenftified in other refinery permits.	Although it is recognized that these cooling towers are small from an emissions standpoint, a conductivity must be assumed in order to calculate emissions, and PSD thresholds are being approached. Because water conductivity is monitored for process control reasons anyway, and with further discussion with Phillips 66, the conditions have remained as proposed, with addition of language indicated alternative monitoring methods may be approved by the Department.
Randall Richert, Phillips 66 Company	Permit Analysis, pages 1 and 2 –	Should the refinery and Jupiter Plant EPN tables be updated to reflect the new EPNs proposed with the project?	Because it has been agreed that an acceptable approach for this permitting action is for the permit to be re-organized when the conditions are applicable, update to the EPN tables should occur at that time. No changes have been

Person /Group Commenting	Draft Permit Reference	Comment	Department Response
			made to this table as a result of this project at this time.
Randall Richert, Phillips 66 Company	Permit Analysis, pages 18 and 19	For the MAQP #2619-31 Table 1, please add notes to the table denoted with asterisks	In MAQP #2619-31, the table had asterisks defined. The permit has been updated to reflect the original notes.
Randall Richert, Phillips 66 Company	Permit Analysis, page 24 and 25	For the No. 1 H2 Unit Reformer Heater, and No. 2 H2 Unit Reformer Heater, please correct the maximum capacity reference for natural gas and cryo gas to reflect 76.80 MMBtu/hr Natural Gas/Cryo Gas and 79.65 MMBtu/hr Natural Gas/Cryo Gas, respectively	The permit has been updated to the format suggested. The permit previously listed these fuels in a separate manner.
Randall Richert, Phillips 66 Company	Permit Analysis, Page 26	For the API Separator Tanks (EPN 55), please correct the maximum capacity to the following: 132,058 thousand gallons per year	The permit has been updated as requested.
Randall Richert, Phillips 66 Company	Permit Analysis, page 27	Please correct from "See Section VI Ambient Air Impact Analysis" to "See Section V Ambient Air Impact Analysis".	The permit has been updated as requested.
Randall Richert, Phillips 66 Company	Permit Analysis, Section II.C.8	To be consistent with the Permit, please revise this section to incorporate the following changes: • Under NSPS J: • Revise "The Refinery Main Plant Relief Flare. Compliance will be in accordance with 40 CFR 60.11 (d) in lieu of the requirements of 40 CFR 60.104, 105 and 107 (Civil Action No. H-01-4430 ("ConocoPhillips Consent Decree"), Paragraphs 161 4 and 162)" to "The Refinery Main Plant Relief Flare. Compliance will be in accordance with 40 CFR 60.11 (d) in lieu of the requirements of 40 CFR 60.104, 105 and 107 (ARM 17.8.749)"; • Revise "The FCCU (CO, S02, PM and opacity)	The permit has been updated as requested.

Person /Group Commenting	Draft Permit Reference	Comment	Department Response
		(ConocoPhillips Consent Decree, Paragraph 54)" to "The Fluid Catalytic Cracking Unit (FCCU) (CO, 802, PM, and opacity provisions) (ARM 17.8.749)". o Under NSPS Ja, • Add Vacuum Furnace, H-17 (EPN 14) - due to the project; • Add Large Crude Unit Heater, H-24 (EPN 21) - due to the project; • Delete Jupiter Plant SRU; • Delete Jupiter A TS Plant; • Add SRU No. 1 - due to the project; • Add SRU No. 2 - due to the project; • Add SRU No. 3 - due to the project. **o** Under NSPS QQQ, please add the equipment that will be subject to this regulation as a result of the project, as referenced in the permit application.	
Randall Richert, Phillips 66 Company	Permit Analysis Section II.E.1	Please correct the permit fee applicability discussion for this permit action	The permit has been updated.
Randall Richert, Phillips 66 Company	Permit Analysis Section II.F.5	Please correct the affidavit of publication of public notice discussion for this action	The permit has been updated.
Randall Richert, Phillips 66 Company	Permit Analysis pages 43 and 44	Please delete references to these maintenance recordkeeping requirements because they are vague, subject to misinterpretation, and have not been included in recently issued permits for similar sources	The permit has been updated to reflect that MACT DDDDD will suffice as BACT for VOC.
Randall Richert, Phillips 66	Non-Project related comment:	Please refvise this section to incorporate the Main Refinery Flare and Jupiter Flare as subject	This is an administrative change which can be incorporated into the permit at this time.

Person /Group Commenting	Draft Permit Reference	Comment	Department Response
Company	Section II.A.1	to NSPS Ja	
Randall Richert, Phillips 66 Company	Non-Proejct related comment: Section II.C	Add the following permit condition: "Total S02 emissions for refinery and sulfur recovery facilities shall not exceed the limit of 3, 103 TPY (Sections 11.C.1.a-I and 11.C.6). In addition, where applicable, all other federal emission limitations shall be met (ARM 17.8.749)." This condition was in previous permit versions, but apparently was inadvertently deleted in a recent permit amendment (see MAQP #2619-28, Section 11.C.1.k., and Operating Permit OP2619-08 Condition A.24.).	This is an administrative change which can be incorporated into the permit at this time.
Randall Richert, Phillips 66 Company	Section II.C	The emission limitations for Jupiter SRU/ATS Main Stack appear to have been deleted.	The permit has been updated to reflect the currently applicable limits until such time that the project is implemented.
Randall Richert, Phillips 66 Company	Page 14	Please revise from "e. Refinery Fuel Gas Heaters/Furnaces" to "d. Refinery Fuel Gas Heaters/Furnaces" and following sections accordingly ("f' and "g" to "e" and "f').	The permit has been updated as requested.
Randall Richert, Phillips 66 Company	Non-Project related comment: Section II.C.1.e.xvi	This condition should read "CO emissions from the No. 2 H2 Unit Reformer Heater shall not exceed 0.025 lb/mmBtu per rolling 12-month time period. The PSA purge gas used as heater fuel shall be sulfur free (ARM 17.8. 752)." This condition was changed during the New Crude and Vacuum Unit permitting, but the change was contingent upon the construction and operation of the New Crude and Vacuum Unit. The New Crude and Vacuum Unit was not constructed, and therefore the permit condition should revert to the previous version (see MAQP #2619-23, Section 11.C.1 .e.xiv.).	This is an administrative change which can be incorporated into the permit at this time.
Randall Richert, Phillips 66 Company	Non-Project related comment: Section II.E.8	Please revise reference from "Conoco" to "Phillips 66".	This is an administrative change which can be incorporated into the permit at this time.

Person /Group Commenting	Draft Permit Reference	Comment	Department Response
Randall Richert, Phillips 63 Company	Non-Project related comment: Permit Analysis Section, Section II.C.8	To be consistent with the Permit Section, please revise this section to incorporate the following changes. • Under NSPS Ja, • Delete Wastewater Treatment System Thermal Oxidizer (when firing supplemental RFG) - this emissions unit was proposed as part of the New Crude and Vacuum Unit (NCVU) Project, but it was not constructed; • Delete No. 1 H2 Reformer Heater (H-9401) - this applicability was associated with changes proposed for the emissions unit as part of the NCVU Project, but the changes to the unit were not implemented; • Add Refinery Main Plant Relief Flare - this is a correction unrelated to the project. • Under NSPS GGG and GGGa, please correct this information to the NSPS GGG and GGGa information included in Permit No. 2619-31.	This is an administrative change which can be incorporated into the permit at this time.

F. Additional Information

Additional information, such as applicable rules and regulations, BACT/Reasonably Available Control Technology (RACT) determinations, air quality impacts, and environmental assessments, is included in the analysis associated with each change to the permit.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the ARM and are available, upon request, from the Department. Upon request, the Department will provide references for locations of complete copies of all applicable rules and regulations or copies where appropriate.

A. ARM 17.8, Subchapter 1 - General Provisions, including, but not limited to:

1. ARM 17.8.101 Definitions. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment, including instruments and sensing devices, and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by the Department. Phillips 66 shall also comply with monitoring and testing requirements of this permit.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., MCA.

   Phillips 66 shall comply with all requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

4. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means which, without resulting in reduction in the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner that a public nuisance is created.

B. ARM 17.8, Subchapter 2 - Ambient Air Quality, including, but not limited to:

1. ARM 17.8.204 Ambient Air Monitoring
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone
6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
7. ARM 17.8.221 Ambient Air Quality Standard for Visibility
8. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

Phillips 66 must comply with the applicable ambient air quality standards. See Section V Ambient Air Impact Analysis.

C. ARM 17.8, Subchapter 3 - Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged to an outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, Phillips 66 shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.

4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.

5. ARM 17.8.316 Incinerators. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any incinerator, particulate matter in excess of 0.10 grains per standard cubic foot of dry flue gas, adjusted to 12% carbon dioxide and calculated as if no auxiliary fuel had been used. Further, no person shall cause or authorize to be discharged into the outdoor atmosphere from any incinerator emissions that exhibit an opacity of 10% or greater averaged over 6 consecutive minutes.

6. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. (4) Commencing July 1, 1972, no person shall burn liquid or solid fuels containing sulfur in excess of 1 pound of sulfur per million Btu fired. (5) Commencing July 1, 1971, no person shall burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions. Phillips 66 will burn RFG gas, PSA gas, or natural gas, which will meet this limitation.

7. ARM 17.8.324 Hydrocarbon Emissions--Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.

9. <u>ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources</u>. This rule incorporates, by reference, 40 CFR Part 60, NSPS. Phillips 66 is considered an NSPS affected facility under 40 CFR Part 60 and is subject to NSPS Subparts including, but not limited to:

   a. Subpart A, General Provisions, applies to all equipment or facilities subject to an NSPS Subpart as listed below.

   b. Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units shall apply to all affected boilers at the facility which were constructed after June 19, 1984, are larger than 100 MMBtu/hr, and combust fossil fuel.

   c. Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units shall apply to all affected boilers at the facility which were constructed after June 9, 1989, are between 10 MMBtu/hr and 100 MMBtu/hr, and combust fossil fuel.

   d. Subpart J, Standards of Performance for Petroleum Refineries, shall apply to:

      1. All of the heaters and boilers at the Phillips 66 refinery (except those subject to Subpart Ja);

      2. The Claus units at the Jupiter sulfur recovery facility (until it becomes subject to Subpart Ja);

      3. The Refinery Main Plant Relief Flare. Compliance will be in accordance with 40 CFR 60.11(d) in lieu of the requirements of 40 CFR 60.104, 105 and 107 (ARM 17.8.749);

      4. The Jupiter Sulfur Plant Flare (Jupiter Flare, also known as the SRU/Ammonium Sulfide Unit Flare) (ConocoPhillips Consent Decree, Paragraphs 155 and 156) (until it becomes subject to Subpart Ja);

      5. The Fluid Catalytic Cracking Unit (FCCU) (CO, SO_2, PM and opacity provisions (ARM 17.8.749); and

      6. Any other affected equipment

   e. Subpart Ja, Standards for Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007, shall apply to:

      1. New Vacuum Furnace H-17 resulting from the Vacuum Improvement Project permitted in MAQP 2619-32

2. Large Crude Unit Heater H-24 resulting from the Vacuum Improvement Project permitted in MAQP 2619-32

3. Jupiter Sulfur Plant Flare (Jupiter Flare, also known as the SRU/Ammonium Sulfide Unit Flare);

4. Sulfur Recovery Unit No. 1 resulting from the Vacuum Improvement Project permitted in MAQP 2619-32

5. Sulfur Recovery Unit No. 2 resulting from the Vacuum Improvement Project permitted in MAQP 2619-32

6. Sulfur Recovery Unit No. 3 resulting from the Vacuum Improvement Project permitted in MAQP 2619-32

7. Delayed Coking Unit

8. Refinery Main Plant Relief Flare

9. Any other affected equipment

f. Subpart Ka, Standards of Performance for Storage Vessels for Petroleum Liquids, shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after May 18, 1978, and prior to July 23, 1984, for equipment not overridden by 40 CFR 63, Subpart CC. These requirements shall be as specified in 40 CFR 60.110a through 60.115a. The affected tanks include, but are not limited to:

Tank ID	Contents
T-100 *	Asphalt
T-101*	Asphalt
T-102	Naphtha
T-104 *	Vacuum Resid

* *Currently exempt from all emission control provisions due to vapor pressure of materials stored.*

g. Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984, for equipment not overridden by 40 CFR 63, Subpart CC. These requirements shall be as specified in 40 CFR Part 60.110b through 60.117b. The affected tanks include, but are not limited to, the following:

Tank ID	Contents
T-35	Slop oil
T-36	(currently out of service)
T-72	Gasoline
T-107*	Residue

T-110	Material with a max true vapor pressure of 11.1 psia
T-0851	(No. 5 HDS Feed Storage Tank)
T-1102	(Crude Oil Storage Tank)
T-2909	Gasoline – Low Sulfur

* *Currently exempt from all emission control provisions due to vapor pressure of materials stored.*

h. Subpart UU, Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture, shall apply to, but not be limited to, asphalt storage tank T-3201, and any other applicable storage tanks that commenced construction or modification after May 26, 1981. Asphalt storage tank T-3201 shall comply with the standards in 40 CFR 60.472(c), and 0% opacity, except for one consecutive 15-minute period in any 24-hour period when transfer lines are being blown for clearing. The PMA unit will be operating at 400^{o}F, well under the asphalt's smoking temperature of 450^{o}F; therefore, the tank vent opacity will always have 0% opacity. There are no record-keeping requirements under this subpart. However, any malfunction must be reported as required under ARM 17.8.110, Malfunctions.

i. Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries, shall apply to, but not be limited to, the delayed coker unit, cryogenic unit, hydrogen membrane unit, gasoline merox unit, crude vacuum unit (until no longer in service), gas oil hydrotreater unit (consisting of a reaction section, fractionation section, and an amine treating section), No.1 Hydrogen Unit (22.0-MMscfd hydrogen plant feed system), Alkylation Unit Butane Defluorinator Project (consisting of heat exchangers X-453, X-223, X-450, X-451, X-452; pump P-646; and vessels D-130, D-359, D-360), Alkylation Unit Depropanizer Project, new fugitive components associated with boilers B-5 and B-6; the fugitive components associated with the No.2 H_2 Unit and the No.5 HDS Unit; C3901 Coker Unit Wet Gas Compressor; C-5301 Flare Gas Recovery Unit Liquid Ring Compressor; C-5302 Flare Gas Recovery unit Liquid Ring Compressor; C-8301 Cryo Unit Inlet Gas Compressor; C-8302 Cryo Unit Refrigerant Compressor; C-8303 Cryo unit Regeneration Gas Compressor; and any other applicable equipment constructed or modified after January 4, 1983.

The C-8401 No. 4 HDS Makeup/Recycle Hydrogen Compressor, C-7401 Hydrogen Makeup/Reformer Hydrogen Compressor, C-9401 Hydrogen Plant Feed Gas Compressor, C-9501 Makeup/Recycle Gas Compressor, and C-9701 Feed Gas Compressor are in hydrogen service.

j. Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, shall apply to the C-8402 Makeup/Recycle Hydrogen Compressor; and any other applicable equipment constructed, reconstructed, or modified after November 7, 2006.

k. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems shall apply to, but not be limited to, the coker unit drain system, desalter wastewater break tanks, CPI separators, gas oil hydrotreater, No.1 Hydrogen Unit (20.0-MMscfd hydrogen plant), C-23 compressor station, Alkylation Unit Butane Defluorinator Project, Alkylation Unit Depropanizer Project, the new individual drain system in the No.2 H_2 Unit, the aggregate facility of the Vacuum Unit including the main oily wastewater sump through and including the two new parallel API OWSs and Tank T-164 as proposed in MAQP 1821-32 and the No.5 HDS Unit, Tank T-4523, and any other applicable equipment, for equipment not overridden by 40 CFR 63, Subpart CC.

l. Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines shall apply to, but not be limited to diesel fired engine used for operation of the Backup Coke Crusher.

m. All other applicable subparts and referenced test methods.

9. ARM 17.8.341 Emission Standards for Hazardous Air Pollutants. Phillips 66 shall comply with the standards and provisions of 40 CFR Part 61, as listed below:

a. Subpart A, General Provisions applies to all equipment or facilities subject to a NESHAP Subpart as listed below.

b. Subpart FF, National Emission Standards for Benzene Waste Operations shall apply to, but not be limited to, all new or recommissioned wastewater sewer drains associated with the Alkylation Unit Depropanizer Project, the refinery's existing sewer system (including maintenance and water draw down activities of the LSG tank involving liquids that may include small concentrations of benzene), the new individual drain system for the waste streams associated with the No.2 H_2 Unit and the No.5 HDS Unit, Tanks 34 and 35.

c. Subpart M, National Emission Standard for Asbestos shall apply to, but not be limited to, the demolition and/or renovation of regulated asbestos containing material.

10. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR Part 63, shall comply with the requirements of 40 CFR Part 63, as listed below:

a. Subpart A, General Provisions, applies to all NESHAP source categories subject to a Subpart as listed below.

b. Subpart R, National Emission Standards for Gasoline Distribution Facilities, shall apply to, but not limited to, the Bulk Loading Rack.

c. Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (Refinery MACT I).

d. Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (Refinery MACT II), shall apply to, but not be limited to, the FCCU, and the Catalytic Reforming Unit #2. Subpart UUU does not apply to the Catalytic Reforming Unit #1 as long as the reformer is dormant or the catalyst is regenerated off-site.

e. Subpart EEEE National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline); shall apply to, but not be limited to, Proto storage tanks.

f. Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, shall apply to, but not be limited to the diesel-fired engine used for operation of the Backup Coke Crusher, the Cryo Backup Air Compressor engine, the Boiler House Air Compressor engine, the Pump for Storm Water to Holding Pond engine, and the Boiler House Backup Air Compressor engine.

D. ARM 17.8, Subchapter 4 - Stack Height and Dispersion Techniques, including, but not limited to:

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.402 Requirements. Phillips 66 must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP).

E. ARM 17.8, Subchapter 5 - Air Quality Permit Application, Operation and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. The correct permit fee was paid by Phillips 66.

2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit, excluding an open burning permit, issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

F. ARM 17.8, Subchapter 7 - Permit, Construction, and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit alteration to construct, alter or use any air contaminant sources that have the PTE greater than 25 tons per year of any pollutant. Phillips 66 has the PTE greater than 25 tons per year of PM, PM_{10}, NO_X, CO, VOC, and SO_2; therefore, an air quality permit is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

4. ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, alteration, or use of a source. A permit application was not required for the current permit action because the permit change is considered an administrative permit change. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. Phillips 66 posted public notice in the *Billings Gazette* on September 20, 2014.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this permit analysis.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving Phillips 66 of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*.

10. ARM 17.8.759 Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.

11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or modified source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 178.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of intent to transfer, including the names of the transferor and the transferee, is sent to the Department.

15. ARM 17.8.770 Additional Requirements for Incinerators. This rule specifies the additional information that must be submitted to the Department for incineration facilities subject to 75-2-215, MCA.

G. ARM 17.8, Subchapter 8 - Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications --Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow.
Phillips 66's existing petroleum refinery in Billings is defined as a "major stationary source" because it is a listed source with the PTE more than 100 tons per year of several pollutants (PM, PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, and VOCs).

The current permit action does not propose a significant net emissions increase, and therefore, is not subject to review as a major modification.

H. ARM 17.8, Subchapter 10 – Preconstruction Permit Requirements for Major Stationary Sources of Modifications Located Within Attainment or Unclassified Areas, including, but not limited to:

1. ARM 17.8.1004 When Montana Air Quality Permit Required. (1) Any new major stationary source or major modification which would locate anywhere in an area designated as attainment or unclassified for a NAAQS under 40 CFR 81.327 and which would cause or contribute to a violation of a NAAQS for any pollutant at any locality that does not or would not meet the NAAQS for that pollutant, shall obtain from the Department a MAQP prior to construction in accordance with subchapters 7 and 8 and all requirements contained in this subchapter if applicable.

This current permit action does not constitute a major modification. Therefore, the requirements of this subchapter do not apply to this action.

I. ARM 17.8, Subchapter 12 - Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any stationary source having:

a. PTE > 100 TPY of any pollutant;

b. PTE > 10 TPY of any one HAP, PTE > 25 TPY of a combination of all HAPs, or a lesser quantity as the Department may establish by rule; or

c. PTE > 70 TPY of PM_{10} in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program Applicability. (1) Title V of the FCAA Amendments of 1990 requires that all sources, as defined in ARM 17.8.1204 (1), obtain a Title V Operating Permit. In reviewing and issuing MAQP #2619-32 for Phillips 66, the following conclusions were made:

   a. The facility's PTE is greater than 100 TPY for several pollutants.

   b. The facility's PTE is greater than 10 TPY for any one HAP and greater than 25 TPY of all HAPs.

   c. This source is not located in a serious PM_{10} nonattainment area.
   d. This facility is subject to NSPS requirements.

   e. This facility is subject to NESHAP standards.

   f. This source is not a Title IV affected source, nor a solid waste combustion unit.

   g. This source is not an EPA designated Title V source.

   Based on these facts, the Department determined that Phillips 66 is subject to the Title V operating permit program.

III. BACT Determination

A BACT determination is required for each new or modified source. Phillips 66 shall install on the new or modified source the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be used.

Refinery Fuel Gas Fired Heaters

The process heaters reviewed for this permitting action will be fired on refinery fuel gas. Refinery fuel gas is usually a mixture of natural gas purchased by the refinery and certain gaseous streams generated at the refinery. By combusting RFG in the process heaters, the refinery uses the heat of combustion of the gaseous streams to heat certain process fluids and generate steam rather than venting these hydrocarbon-containing gaseous streams in a non-combusted manner or combusting the same streams in a flare and not recovering the associated heat of combustion for useful purposes. Below is a pollutant-by-pollutant review of BACT for these process heaters.

SO_2 Emissions

- Flue Gas Desulfurization

Flue gas desulfurization is commonly used to reduce SO_2 emissions from coal-fired and oil-fired combustion sources due to the relatively high concentration of SO_2 (thousands of ppmv) contained in the exhaust gases from these sources. Flue gas desulfurization consists of wet, semi-dry, and dry scrubbers. In a wet scrubber, an aqueous slurry of sorbent is injected into the exhaust gases and the SO_2 contained in these gases dissolves into the slurry droplets where it reacts with the alkaline present in the slurry. The treated exhaust gases pass through a mist eliminator before being emitted to the atmosphere in order to remove any entrained slurry droplets. The slurry falls to the bottom of the scrubber and is either collected to be regenerated and recycled or removed from the scrubber system as a waste or byproduct. Semi-dry scrubbers are similar to wet scrubbers, but the slurry has a higher sorbent concentration, which results in the complete evaporation of the water in the slurry and the formation of a dry spent sorbent material that is entrained in the treated exhaust gases. This dry spent sorbent is removed from the treated exhaust gases using a baghouse or electrostatic precipitator. In a dry scrubber, a dry sorbent material is pneumatically injected into the exhaust gases and the dry spent sorbent material entrained in the treated exhaust gases is removed using a baghouse or ESP. Wet scrubbers are capable of higher SO_2 control efficiencies than semi-dry and dry scrubbers.

Wet, semi-dry, and dry scrubbers are not believed to be technically feasible for the control of SO_2 emissions from the refinery fuel gas heaters due to the low SO_2 concentration of the exhaust gases. The SO_2 concentration in the exhaust gases from the process heaters will be near the levels exiting many flue gas desulfurization scrubbers, which indicates that it would not be technically or economically feasible to install and operate a flue gas desulfurization scrubber on these heaters. Furthermore, the universal practice of not using flue gas desulfurization to control SO_2 emissions from a combustion source firing refinery fuel gas that has been treated to remove hydrogen sulfide indicates that it is not practical to use flue gas desulfurization for these heaters.

Because the sulfur content of the fuel combusted by a combustion device directly influences the quantity of SO_2 emissions resulting from the combustion of a gaseous fuel, and most refineries already employ a sulfur reducing process to the refinery fuel gas stream, this option was analyzed in more detail.

- Fuel Sulfur Content

The gaseous streams blended into RFG at the refinery can be treated to remove a considerable amount of hydrogen sulfide that may be contained in these streams. The only technique known to be used by petroleum refineries to remove hydrogen sulfide from RFG streams is amine treatment. Consistent with this understanding, the refinery includes three amine treating units: the No. 1 Amine Unit, No. 2 Amine Unit, and No. 3 Amine Unit. The amine treatment process is a chemical absorption process by which hydrogen sulfide is scrubbed from refinery fuel gas using a water solution of organic amine (alkanolamines) in a packed or tray tower. Alkanolamines are categorized as being primary, secondary, or tertiary, depending upon the number of organic groups attached to the central nitrogen atom. The amine solution used in the amine treatment process is a weak organic base and the hydrogen sulfide included in the refinery fuel gas is acidic. The hydrogen sulfide readily dissolves in the amine solution and the acidic hydrogen sulfide reacts with the basic organic amine to form an acid-base complex (salt), thus removing hydrogen sulfide from the fuel. The amine solution high in salt content exits the amine treatment scrubber and is then sent to a stripping tower where it is heated to elevated temperatures, resulting in the reversal of the chemical absorption reactions that occurred in the amine treatment scrubber such that the hydrogen sulfide is released from the amine solution. The overhead stream from this stripping operation, which contains hydrogen sulfide and is referenced as "acid gas", is ultimately routed to the Jupiter Plant where the sulfur contained in the acid gas is almost entirely recovered. The regenerated amine solution exiting the stripping tower is recycled back to the amine treatment scrubber.

Amine treatment represents the only technique known to be used by petroleum refineries to remove hydrogen sulfide from refinery fuel gas streams. According to ARM 17.8.740(2), defining BACT, in no event may BACT exceed the emissions allowed by any applicable standard under ARM Title 17, Chapter 8, Subchapter 3. 40 CFR 60 Subpart Ja (NSPS Ja) would be applicable to new heaters, and to those heaters considered modified as defined for purposes of NSPS. The current permit action permits changes to some heaters which will not meet the definition of modified under NSPS, and therefore would be subject to NSPS J instead of NSPS Ja. However, the Department has determined that for all process heaters submitted as modified for pursposes of PSD review, the heaters will be required to meet the limits of NSPS Ja. This was determined technically and economically feasible, and these limits serve multiple purposes, as BACT for new and modified units, and also as necessary to satisfactorily meet ambient air quality impact analyses. Therefore, in some cases, BACT or other emissions limitations selected is more stringent than NSPS would require.

NO_X Emissions

NO_X is formed by three mechanisms: thermal NOx, fuel NOx, and prompt NOx. In natural gas combustion, NOx is primarily produced via the thermal and prompt NOx mechanisms. Thermal NOx results from the high temperature thermal dissociation and subsequent reaction of combustion air molecular nitrogen and oxygen. Thermal NOx tends to be generated in the high temperature zone near the burner of an external combustion device. The rate of thermal NOx generation is affected by the following three factors: oxygen concentration, peak temperature, and the duration at peak temperature. As these three factors increase in value, the rate of thermal NOx generation increases. Fuel NOx is formed by the direct oxidation of organo-nitrogen compounds contained in a fuel stream. Therefore, fuel NOx emissions increase with an increase in the quantity of nitrogen-containing organic compounds present in a fuel.

Prompt NOx occurs at the flame front through the relatively fast reaction between nitrogen and oxygen molecules in the combustion air and fuel hydrocarbon radicals that are intermediate species formed during the combustion process. Prompt NOx levels are usually a small fraction of overall NOx emissions levels in natural gas-fired combustion equipment. However, because the prompt NOx mechanism can become a considerable factor in lower temperature combustion processes in some NOx control technologies, it can represent a considerable portion of the NOx emissions resulting from certain ULNBs.

- Selective Catalytic Reduction (SCR)

SCR is a post-combustion treatment technology that promotes the selective catalytic chemical reduction of NOx (both nitric oxide and nitrogen dioxide) to molecular nitrogen and water. SCR can achieve NOx emissions reductions of up to 95%; however, NOx emissions reductions between 80 and 90% are typically achieved by this technology. For a combustion device equipped with an SCR system, a reducing agent (aqueous or anhydrous ammonia or urea) is mixed with NOx-containing combustion gases and the resulting mixture is passed through a catalyst bed, which catalyst serves to lower the activation energy of the NOx reduction reactions. In the catalyst bed, the NOx and ammonia contained in the combustion gas-reagent mixture are adsorbed onto the SCR catalyst surface to form an activated complex and then the catalytic reduction of NOx occurs, resulting in the production of nitrogen and water from NOx. The nitrogen and water products of the SCR reaction are desorbed from the catalyst surface into the combustion exhaust gas passing through the catalyst bed. From the SCR catalyst bed, the treated combustion exhaust gas is emitted to the atmosphere. SCR systems can effectively operate at a temperature above 350 °F and below 1,100 °F, with a more refined temperature window dependent on the composition of the catalyst used in the SCR system.

In 2008, Phillips 66 (then ConocoPhillips Company) submitted an air permit application requesting authorization from the MT DEQ to implement the New Crude and Vacuum Unit (NCVU) Project at the refinery. The MT DEQ authorized the NCVU Project to be conducted at the refinery with the issuance of Montana air quality permit 2619-24 on November 19, 2008. Phillips 66 ultimately did not implement the NCVU Project at the refinery. However, as part of that permitting effort, Phillips 66 estimated a total capital investment of approximately $1,090,807 for the installation of an SCR system on a new RFG-fired process heater rated at 58 MMBtu/hr and estimated to emit NOx at an uncontrolled level of 0.042 lb/MMBtu. Phillips 66 also estimated that the total annualized cost for the installation and operation of this SCR system would be approximately $341,604 per year. Based on these cost estimates, the MT DEQ determined that the installation and operation of an SCR system on the proposed 58 MMBtu/hr process heater was not cost effective for PSD BACT purposes. Likewise, SCR can be determined economically infeasible for the process heaters of this project.

- Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion treatment technology that is effectively a partial SCR system. For a combustion device equipped with an SNCR system, a reducing agent (aqueous or anhydrous ammonia or urea) is mixed with NOx-containing combustion gases and a portion of the NOx (both nitric oxide and nitrogen dioxide) reacts with the reducing agent to form molecular nitrogen and water; however, as indicated by the name of this technology, an SNCR system does not utilize a catalyst to promote the chemical reduction of NOx.

Because a catalyst is not used in an SNCR system, the NOx reduction reactions in this system occur at high temperatures. SNCR requires thorough mixing of the reagent in the upper combustion chamber of an external combustion device and this technology requires at least 0.5 seconds of residence time at a temperature above 1,600 °F and below 2,100 °F. A combustion device equipped with SNCR technology may require multiple reagent injection locations because the optimum location (temperature profile) for reagent injection may change depending on the load at which the combustion device is operating. At temperatures below 1,600 °F, the desired NOx reduction reactions will not effectively occur and much of the injected reagent will be emitted to the atmosphere along with the mostly uncontrolled NOx emissions. At temperatures above 2,100 °F, the desired NOx reduction reactions will not effectively occur and the ammonia or urea reagent will begin to react with available oxygen to produce additional NOx emissions.

Design and operational technical difficulties would be expected with the retrofit installation of SNCR reagent injection points in the upper firebox area of existing units, especially considering the fact that these difficulties significantly increase for the retrofit installation of an SNCR system on smaller process heaters. Alternatively, the installation of duct burners in the exhaust of smaller heaters would require additional energy consumption and negatively generate additional combustion emissions. SNCR systems often have not achieved the amount of theoretical NOx emissions reduction expected before their installation, especially in retrofit scenarios. Compounding technical issues is that the lower the inlet concentration of NOx in the gas stream routed to an SNCR system, the poorer the NOx removal performance of such system.

SNCR is feasible from a technical standpoint; however, prelimanary estimated costs result in significant cost per ton figures for each process heater which justifies elimination of SNCR from further consideration for the process heaters of this project.

- Non-selective catalytic reduction (NSCR)

NSCR is a post-combustion treatment technology that promotes the catalytic chemical reduction of NOx (both nitric oxide and nitrogen dioxide) to molecular nitrogen and water. NSCR has been applied to nitric acid plants and rich burn (0.3 to 0.5% excess oxygen) and stoichiometric internal combustion engines to reduce NOx emissions. For those source types, NSCR typically achieves an 80-95% reduction in NOx emissions. NSCR uses a reducing agent (hydrocarbon, hydrogen, or CO), which can be inherently contained in the exhaust gas due to rich combustion conditions or injected into the exhaust gas, to react in the presence of a catalyst with a portion of the NOx contained in the source's exhaust gas to generate molecular nitrogen and water. NSCR systems can effectively operate at a temperature above 725 °F and below 1,200 °F, with a more refined temperature window dependent on the source type and composition of the catalyst used in the NSCR system.

NSCR is not believed to be technically feasible for the control of NOx emissions from the process heaters because the heaters will not operate at the 0.5% or less excess oxygen concentration necessary to ensure NOx reduction with an NSCR system. These heaters as proposed would operate with excess oxygen concentrations equal to approximately 3%. Additionally, sulfur poisoning and hence catalyst deactivation would be a potential concern for the application of NSCR in this application.

- Flue Gas Recirculation (FGR) and Low/Ultra Low NO_X Burners (LNB/ULNB):

Combustion technique NOx control technologies incorporate one or more of the following concepts: 1) lower the flame temperature; 2) create a fuel rich condition at the maximum flame temperature; or 3) lower the residence time under which oxidizing conditions exist. LNBs/ULNBs are available in a variety of configurations and burner types. In LNBs/ULNBs, fuel and air are often pre-mixed prior to combustion, resulting in a lower and more uniform flame temperature. Pre-mix burners may require the aid of a blower to mix the fuel with air before combustion takes place. FGR, recycling a portion of the combustion exhaust gases back into the burner, is commonly used with these burners in order to reduce flame temperature. In addition to flue gas, steam can be used as a diluent to reduce flame temperature. LNBs/ULNBs can also use staged combustion with a fuel rich zone to start combustion and stabilize the flame and a fuel lean zone to complete combustion and reduce the peak flame temperature. These types of burners can also be designed to spread flames over a larger area to reduce hot spots and lower NOx emissions. ULNBs require sophisticated process controls to stabilize the flame and maintain emissions levels and efficiency across a wide range of turndown ratios that is sufficient for the demands of the particular operation.

According to ARM 17.8.740(2), defining BACT, in no event may BACT exceed the emissions allowed by any applicable standard under ARM Title 17, Chapter 8, Subchapter 3. 40 CFR 60 Subpart Ja (NSPS Ja) would be applicable to new heaters, and to those heaters considered modified as defined for purposes of NSPS. The current permit action permits changes to some heaters which will not meet the definition of modified under NSPS, and therefore would be subject to NSPS J instead of NSPS Ja. Phillips 66 proposed emissions rates equivalent to, or more stringent than, NSPS Ja, by utilizing ULNB technology for all process heaters. This was determined technically and economically feasible, and these limits serve multiple purposes, as BACT for new and modified units, and also as necessary to satisfactorily meet ambient air quality impact analyses. In some cases, limits proposed as BACT is more stringent than NSPS would require, and the Department has accepted these limitations as proposed by Phillips 66, as BACT.

CO Emissions

CO emissions result from the incomplete combustion of hydrocarbons present in fuel. Improperly tuned gaseous fuel combustion devices and combustion devices operating outside of design levels experience a decrease in combustion efficiency, which can result in increased CO emissions. Additionally, poor maintenance of combustion device burners/combustion air components can result in increased CO emissions due to a decrease in combustion efficiency.

- Proper design, operation, and maintenance

Good combustion practices for an external combustion device such as a process heater include: proper burner and combustion source design; good burner (including fuel and combustion air delivery systems) maintenance and operation; and effective fuel and combustion air mixing. Combustion control is the most effective means for reducing CO emissions from gaseous fuel process heaters. Fuel combustion efficiency is most simply related to the following three variables: time, temperature, and turbulence. A process heater is designed such that these three variables are optimized to maximize fuel combustion efficiency so that operating costs (e.g., fuel usage) are minimized while productive functions (process heating) are maximized. Therefore, combustion control is accomplished primarily through heater/burner design and proper operation and maintenance of the same.

Excess air affects combustion efficiency. Very low or very high excess air levels will result in high CO emissions. Very low excess air conditions result in higher CO emissions because insufficient oxygen is available to complete combustion of the hydrocarbons contained in the fuel from CO to CO_2. Very high excess air conditions lower the combustion zone temperature, and this lower temperature reduces the combustion efficiency of CO to CO_2.

- Oxidation Catalyst

Oxidation catalysts can be used to convert CO present in combustion exhaust gas to CO_2. In regard to gaseous fuel combustion devices, this technology has almost exclusively been applied to natural gas-fired turbines and internal combustion engines combusting low sulfur fuels. Fundamentally, oxidation catalysts lower the activation energy required for the oxidation of CO to CO_2; in the case of a combustion device, the excess air in the combustion exhaust gas passing through the oxidation catalyst bed provides the oxygen necessary for the CO to CO_2 oxidation reaction.

An oxidation catalyst can experience sulfur poisoning and hence catalyst deactivation when treating exhaust gases from an RFG-fired combustion device, which would considerably limit the CO removal efficiency of such catalyst. Furthermore, oxidation catalysts can increase the conversion of SO_2 to SO_3, which increases the potential for the formation of condensable PM emissions and flue gas equipment corrosion rates. For these reasons, catalytic oxidation is questionable as a technically feasible option from the process heaters.

The Department determined that proper design, operation, and maintenance will meet BACT. Initial source testing, ongoing recordkeeping of maintenance performed, and periodic CO emissions optimization required by 40 CFR 63 Subpart DDDDD will be the prescribed BACT demonstration methodology. Further, the emissions levels assumed as a result of the prescribed BACT are necessary from an ambient air quality impacts analyses standpoint.

PM Emissions

PM, PM_{10}, and $PM_{2.5}$ emissions occur from refinery fuel gas fired process heaters as a result of the incomplete combustion of higher molecular weight hydrocarbons present in the gaseous fuel combusted. However, the RFG combusted will contain low levels of high molecular weight hydrocarbons. Furthermore, the gaseous streams generated at the refinery are treated, as needed, to partially remove hydrogen sulfide so that the amount of hydrogen sulfide contained in the RFG is at low levels. Incomplete combustion in a gaseous fuel combustion device such as this heater can occur because of poor fuel-air mixing and improper combustion mechanisms. These causes of incomplete combustion can be associated with poor burner/combustion device design, operation, and/or maintenance. The PM emissions resulting from the RFG fired heaters will have both filterable and condensable portions, but the PM emissions will generally be less than 10 μm in diameter.

The Department determined that proper design, operation, and maintenance will meet BACT. Ongoing recordkeeping of maintenance performed, and periodic emissions optimization required by 40 CFR 63 Subpart DDDDD will be the prescribed BACT demonstration methodology.

VOC Emissions

VOC emissions occur from refinery fuel gas fired heaters as a result of the incomplete combustion of hydrocarbons present in the gaseous fuel combusted in this heater. Incomplete combustion in a gaseous fuel combustion device such as this heater can occur because of poor fuel-air mixing and improper combustion mechanisms. These causes of incomplete combustion can be associated with poor burner/combustion device design, operation, and/or maintenance.

- Catalytic Oxidation

Oxidation catalysts can be used to convert VOCs present in combustion exhaust gas to CO_2. In regard to gaseous fuel combustion devices, this technology has almost exclusively been applied to natural gas-fired turbines and internal combustion engines combusting low sulfur fuels. Fundamentally, oxidation catalysts lower the activation energy required for the oxidation of VOCs to CO_2; in the case of a combustion device, the excess air in the combustion exhaust gas passing through the oxidation catalyst bed provides the oxygen necessary for the VOCs to CO_2 oxidation reaction.

An oxidation catalyst can experience sulfur poisoning and hence catalyst deactivation when treating exhaust gases from an RFG-fired combustion device, which would considerably limit the VOC removal efficiency of such catalyst. Furthermore, oxidation catalysts can increase the conversion of SO_2 to SO_3, which increases the potential for the formation of condensable PM emissions and flue gas equipment corrosion rates. For these reasons, technically feasibility is questionable to use on refinery fuel gas fired process heaters.

- Proper Operation, Design, and Maintenance

Good combustion practices for an external combustion device such as a process heater include: proper burner and combustion source design; good burner (including fuel and combustion air delivery systems) maintenance and operation; and effective fuel and combustion air mixing. Combustion control is the most effective means for reducing VOC emissions from gaseous fuel process heaters. Fuel combustion efficiency is most simply related to the following three variables: time, temperature, and turbulence. A process heater is designed such that these three variables are optimized to maximize fuel combustion efficiency so that operating costs (e.g., fuel usage) are minimized while productive functions (process heating) are maximized.

The Department determined that compliance with MACT DDDDD will meet the requirements of BACT for these sources.

Cooling Towers

The operation of the Cooling Tower (EPN 53) and Jupiter Cooling Tower, CT-602 (EPN 5) that are proposed to be installed with the project will result in emissions to the atmosphere because a portion of any chemical impurities and hydrocarbons contained in the water that is recirculated in these cooling towers will become airborne due to the direct contact between the cooling water and air passing through the towers. In regard to PM emissions, as part of normal operation, a small amount of the circulating water may be entrained in the air stream and carried out of these towers as "drift" droplets. These drift droplets contain the same chemical impurities (total dissolved solids (TDS)) as the water circulating through the towers. The chemical impurities contained in the drift droplets ultimately represent the PM emissions from these wet cooling towers.

VOC emissions occur from a wet cooling tower because the non-contact heat exchangers (e.g., shell and tube heater exchanger) through which the recirculated cooling water flows can develop a leak, which can allow hydrocarbon-containing process material to enter into the cooling water if the pressure of the process material is greater than that of the cooling water. The VOCs contained in this process material are then emitted to the atmosphere when the contaminated cooling water is recirculated through the cooling tower because of the stripping effect of the air and cooling water contact in the cooling tower.
PM Emissions

- Air-Cooled Heat Exchanger

  Air-cooled heat exchangers use indirect air contact to cool the relevant process fluid or water that is used to cool the relevant process fluid. In either scenario, the process fluid or water is contained in tubes that generally have fins attached to the external surface of the tubes and ambient air flows across the surface of these fins. This air flow can be forced draft or induced draft. The heat transfer related limitation on the use of an air-cooled heat exchanger is the peak ambient air temperature at a particular location and the temperature to which the process fluid must be cooled. Air-cooled heat exchangers are not feasible for scenarios in which a process fluid must be cooled to a temperature less than approximately 25 °F above the ambient air temperature. For example, if the ambient air temperature is 80 °F, then an air-cooled heat exchanger would likely not be able to cool a process fluid to a temperature below 105 °F. Additionally, the size of an air-cooled heat exchanger can be significantly larger than a wet cooling tower, which can limit the application of an air-cooled heat exchanger when available space is limited and/or practical equipment layout prohibits such a large exchanger. Furthermore, as the amount of cooling required for a particular operation increases, the capital cost of an air-cooled heat exchange system can become considerably greater than a wet cooling tower system.

  The use of air-cooled heat exchangers was not considered to be technically feasible in this instance because this type of heat exchanger would not provide adequate cooling during the summer months for the heat exchangers to be serviced. Additionally, the use of air-cooled heat exchangers for the condensers in the new three-stage ejector vacuum system that is planned for the replacement Vacuum Unit Fractionator and that will be serviced by one of the two new cooling towers would introduce a considerable pressure drop in the vacuum system due to the size of the air-cooled heat exchange equipment that would be required.

- Design of Wet Cooling Tower

Wet cooling towers rely on the latent heat of water evaporation to exchange heat between the process being cooled and the air passing through the cooling tower. A wet cooling tower provides direct contact between the cooling water and air passing through the tower; therefore, as part of normal operation, a small amount of the circulating water may be entrained in the air stream and carried out of the tower as "drift" droplets. Drift eliminators reduce the emission of water droplets from a wet cooling tower, thereby reducing the PM emissions from this type of cooling tower. Drift eliminators are placed where the air flow exits the cooling tower, and these devices rely on inertial separation caused by direction changes while the exiting air stream passes through the eliminators to remove entrained water. Current day drift eliminators are recognized as "high efficiency" drift eliminators due to the high water entrainment removal efficiency achieved by these devices.

Phillips 66 shall control PM, PM_{10}, and $PM_{2.5}$ emissions from the cooling towers by utilizing a high efficiency drift eliminator. The high efficiency drift eliminator shall be designed to limit the drift rate to no more than 0.0010%.

VOC Emissions

Emissions of VOCs occur from a wet cooling tower because the non-contact heat exchangers (e.g., shell and tube heater exchanger) through which the recirculated cooling water flows can develop a leak, which can allow hydrocarbon-containing process material to enter into the cooling water. The VOCs contained in this process material are then emitted to the atmosphere when the contaminated cooling water is recirculated through the cooling tower because of the stripping effect of the air and cooling water contact in the cooling tower.

Monitoring and repair practices are used to reduce VOC emissions from a wet cooling tower by monitoring the water that is recirculated in the cooling tower for VOCs and then repairing any heat exchangers integrated with the cooling tower that may be leaking VOC-containing process material into the recirculated cooling water. The components of a cooling tower system monitoring and repair program that impact its VOC emissions control effectiveness are cooling water return line monitoring frequency, the level of measured VOC content indicating a heat exchanger leak, and heat exchanger repair requirements. For comparison to a monitoring and repair program, a heat exchanger employing an inert intervening fluid between the process material intended to be cooled and the recirculating cooling water would typically isolate the process material from the cooling water, which would be expected to reduce the potential for leakage of process material into the cooling water. However, this heat exchanger design would have a reduced heat transfer efficiency, which would result in an increase in capital cost because such a heat exchanger would be larger and more complex in design and construction. Additionally, the reduced heat transfer efficiency of a heat exchanger incorporating an intervening fluid would likely result in an increase in operating cost because the amount of cooling water necessary may be greater and/or the supply temperature of the cooling water may need to be lower in order to achieve the desired amount of process cooling. Furthermore, this heat exchanger design could eventually develop leaks that would allow the VOC-containing process material to leak into the recirculating cooling water; therefore, monitoring and repair requirements would be expected to be necessary for this type of heat exchanger as well. Due to these costs and emissions control effectiveness concerns, heat exchangers employing an inert intervening fluid are questionable as BACT due to the high costs with little potential benefit.

40 CFR 63 Subpart CC details a heat exchange monitoring and repair program, which is applicable to heat exhangers associated with the cooling towers. The Department determined that 40 CFR 63 Subpart CC meets BACT for the cooling towers for VOC.

The Department questioned whether VOC containing water treatement chemicals are used in cooling towers at this facility. Philllips 66 response indicates no VOC containing chemicals are used. Further, review of common cooling tower permit conditions did not reveal that VOC limitations on water treatement chemicals are common practice. No VOC emissions associated with water treatment of cooling water were reviewed or accounted for in this permit action.

Wastewater Component Emissions

VOC Emissions

VOC emissions occur from wastewater components (e.g., drains, junction boxes, sumps, wastewater treatment vessels) when the wastewater that is contained or contacted by a component includes VOCs and that component is open to the atmosphere. For example, a drain at a petroleum refinery is typically connected to an oily wastewater sewer line. Therefore, if this drain is open to the atmosphere rather than being equipped with a p-trap (or other equivalent liquid seal) or cap, then the VOCs in the oily wastewater contained in the sewer line can volatilize and be emitted from the open drain.

Various NSPS, NESHAP, and MACT standards are potentially applicable to wastewater component emissions including:

- 40 CFR 60 Subpart QQQ (Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems)
- 40 CFR 61 Subpart FF (National Emission Standard for Benzene Water Operations)
- 40 CFR 63 Subpart CC (National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries)

The above regulations require equipment design (e.g., water seals, caps, covers, floating roofs, collection and control systems, etc.) and monitoring practices to reduce and treat emissions from relevant wastewater management and treatment components.

This project also proposes the installation of additional wastewater fugitive components in the Vacuum Unit and No. 2 HDS Unit at the refinery. Approximately six process drains and one common junction box are planned to be installed in the Vacuum Unit, and one process drain is planned to be installed in the No. 2 HDS Unit. These new process drains and this new junction box will be subject to relevant 40 CFR 60, Subpart QQQ VOC emission standards and relevant benzene control requirements of 40 CFR part 61, subpart FF.
The Department determined that compliance with the aforementioned standards meet BACT for these units.

<u>API Separator Tanks</u>

VOC Emissions

Oil Water Separators (OWS)s are typically the first step in the treatment of oily wastewater generated at a petroleum refinery and are usually used as the primary method of separating and removing oil from oily wastewater. An American Petroleum Institute (API) OWS is one of the most commonly used type of OWS. OWSs rely on the different densities of oil, water, and any solids that may be contained in the oily wastewater undergoing treatment for successful operation. Oils and solids with specific gravities less than that of water float to the surface of the aqueous phase in the OWS, while heavy sludges and solids sink to the bottom of the OWS. VOC emissions occur from an OWS because of the volatilization of VOCs from the oil phase that develops on the surface of the oily wastewater being treated in the OWS. The variables considered to control VOC emissions from an uncovered OWS are the vapor pressure of the influent oil and the wind speed over the OWS. Other factors that can affect the VOC emission rate from an OWS include the surface area of OWS, the frequency of oil skimming, and the thickness of the oil layer at the surface of the OWS.

Various NSPS, NESHAP, and MACT standards are potentially applicable to these tanks including:

- 40 CFR 60 Subpart QQQ (Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems)
- 40 CFR 61 Subpart FF (National Emission Standard for Benzene Water Operations)
- 40 CFR 63 Subpart CC (National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries)

The above regulations require an OWS tank to be equipped with a fixed roof and any vapor between this fixed roof and the liquid surface in the OWS tank that is purged must be directed to a control device (e.g., flare, thermal oxidizer, carbon adsorption device) that meets applicable pollutant destruction/removal requirements. Alternatively, these regulations provide that an OWS tank can be equipped with a floating roof that is designed and maintained to meet certain rim seal and deck fitting specifications and requirements. Phillips 66 proposed to cover and seal the API Separator Tanks and the purged vapor from these tanks routed to activated carbon canisters for 95% control of VOC emissions. The Department found the proposal to meet BACT.

Jupiter Sulfur Recovery Units (SRU)s

The Jupiter Plant currently includes two routinely operated sulfur recovery units (SRUs) and one intermittently operated ammonium sulfide (ASD) absorption column. Below is a general description of the two routinely operated SRUs located at the Jupiter Plant.

- SRU No. 1 is comprised of two sulfur recovery components. One component of this SRU is a Claus thermal reactor process equipped with an ammonium bisulfite (ABS) tail gas treatment process. This first sulfur recovery component receives sour-acid gas from the refinery and converts nearly all of the sulfur contained in this sour-acid gas to elemental sulfur or ABS. The Sulfur Oxidizer (F-102/B-102) located in this sulfur recovery component of SRU No. 1 is configured to receive the vent stream from the ASD absorption column during non-malfunction operations. The exhaust stream from this sulfur oxidizer is routed to the ABS absorption columns of this SRU. The second sulfur recovery component of SRU No. 1 is an ammonium thiosulfate (ATS) absorption column that receives sour-acid gas from the refinery, and this ATS absorption column converts nearly all of the sulfur contained in its sour-acid gas feed to ATS. The vent stream from the ATS absorption column in SRU No. 1 is routed to the Sulfur Oxidizer (F-102/B-102). As previously noted, the exhaust stream from this sulfur oxidizer is routed to the ABS absorption columns of this SRU.

- SRU No. 2 is comprised of Claus thermal and catalytic reactors in series equipped with an ABS tail gas treatment process. The Sulfur Oxidizer (F-304/B-304) included in this SRU is configured to receive the vent stream from the ASD absorption column during non-malfunction operations. The exhaust stream from this sulfur oxidizer is routed to the ABS absorption column of this SRU.

The project proposes modifications to SRU No. 1 and the installation of a third SRU (SRU No. 3) at the Jupiter Plant in order to process the increased amount of sulfur-containing compounds that will be routed to the Jupiter Plant as a result of the project.

The following provides a general scope of some of the notable changes proposed to occur to SRU No. 1 in order to improve its operations.

- One Claus catalytic reactor will be added after the existing Claus thermal process to recover additional elemental sulfur in the unit.

- The existing sulfur oxidizer that currently follows the Claus thermal process will be replaced with a new sulfur oxidizer equipped with ULNBs. This new replacement sulfur oxidizer will follow the new Claus catalytic reactor. The new replacement sulfur oxidizer will be configured to receive the vent stream from the ASD absorption column during non-malfunction operations, the same as the existing sulfur oxidizer.

- One quench tower will be added after the new replacement sulfur oxidizer to remove excess water from this oxidizer's exhaust stream.

- One vent gas filter will be added to the existing dual vent gas filters that follow the ABS absorption columns in the unit.

SRU No. 3 is proposed to be added to the Jupiter Plant and this new SRU will be comprised of two sulfur recovery components. One component of this SRU will be Claus thermal and catalytic reactors in series equipped with an ABS tail gas treatment process. This first sulfur recovery component will receive a portion of the sour-acid gas routed to this SRU and convert nearly all of the sulfur contained in this sour-acid gas to elemental sulfur or ABS. The second sulfur recovery component of SRU No. 3 will be an ATS absorption column that receives the portion of sour-acid gas routed to the unit but not handled in the Claus/ABS component of this SRU, and this ATS absorption column will convert nearly all of the sulfur contained in its sour-acid gas feed to ATS.

SRU No. 3 will include the following major equipment components:

- One Claus thermal reactor;
- One Claus catalytic reactor;
- One sulfur oxidizer equipped with ULNBs;
- One quench tower;
- One ABS absorption column with associated heat exchangers;
- One ATS absorption column with associated heat exchangers;
- Three vent gas filters – two online, one spare;
- One atmospheric vent stack receiving exhaust gas from this SRU only;
- One below grade sulfur pit; and
- One above ground sulfur storage tank.

The new sulfur pit listed above will not have a vent stream routed to the atmosphere. Instead, the vent from this sulfur pit will be routed to the SRU No. 3 sulfur oxidizer, from which the oxidized stream will be routed to the ABS absorption column in SRU No. 3. The sulfur dioxide (SO_2) present in the stream routed to the SRU No. 3 ABS absorption column will almost entirely be converted to ABS.

The Jupiter Plant recovers sulfur to form valuable products, particularly through SRU #1. The application proposes to increase abilities of SRU #1 and install a new SRU, SRU#3, which will operate to form the same products as SRU #1. SRU #2 generally is utilized to form less valuable elemental sulfur.

Because of the Jupiter Plant function, the BACT analysis focused primarily on emissions control of the tail gas from the Sulfur Recovery operations, versus the sulfur recovery operations as a whole. However, a parallel review of sulfur removal technologies in general finds that with capabilities and incentives specific to this project scenario, BACT is

determined to be the same regardless of review of the SRUs as process equipment or pollution control equipment. The configuration proposed for the SRU #3 provides economic benefits in terms of the value of products that can be produced in using such a set up, environmental and economic benefits associated with flexibility in operations of such a setup, is expected to remove 99.94% of the incoming sulfur on a mass basis, and emissions are expected to meet or exceed NSPS standards. Enhancements as part of this project will create higher capacity to produce the higher value products at Jupiter, and given the removal efficiencies offered, such a scenario is deemed BACT in this case-by-case review.
SO_2 emissions:

Emissions of SO_2 result from the oxidation of sulfur-containing compounds included in the tail gas combusted by the Sulfur Oxidizer. However, the purpose of the Sulfur Oxidizer is to convert sulfur-containing compounds to SO_2 and then the SO_2 contained in the exhaust gases from this thermal oxidizer is routed to the ammonia bisulfite (ABS) absorption columns. SO_2 emissions occur due to less than 100% conversion of SO_2 to ABS.

Tail gas treatment systems include one of two types of tail gas scrubbing processes: oxidation tail gas scrubbers or reduction tail gas scrubbers. When an oxidation tail gas scrubber is used, the tail gas stream from the SRU is combusted to convert sulfur-containing compounds to SO_2 and this combustion exhaust stream is then routed to an SO_2 scrubber before being emitted to the atmosphere. Alternatively, when a reduction tail gas scrubber is used, the tail gas stream is processed to convert sulfur in the tail gas to hydrogen sulfide and this hydrogen sulfide laden stream is then routed to a hydrogen sulfide scrubber before being emitted to the atmosphere (or combusted in a thermal oxidizer and then emitted to the atmosphere). The Shell Claus Off-gas Treatment (SCOT) process is the most common reduction tail gas scrubber process used at petroleum refineries in the United States.

SRU No. 1 is equipped with an oxidation tail gas scrubber process that generates an ABS product, and this scrubber process is as effective as any reduction tail gas scrubber process or other oxidation tail gas scrubber process that may be available for an SRU. This effectiveness is illustrated by the fact that SRU No. 1 is currently limited to SO_2 emissions of 167 ppmv (dry basis, at 0% excess oxygen), based on a rolling 12-hour average, while EPA recently determined as part of the 40 CFR part 60, subpart Ja rulemaking process that the application of "best demonstrated technology" on a sulfur recovery plant would achieve SO_2 emissions of 250 ppmv (dry basis, at 0% excess oxygen), based on a rolling 12-hour average. The ABS tail gas treatment process is not only very effective in controlling the amount of sulfur emitted to the atmosphere from SRU No. 1, but the use of this particular tail gas treatment process at the refinery is environmentally beneficial because its presence at the refinery eliminates combustion emissions that would be associated with the transport of elemental sulfur from the refinery to an off-site ABS production facility. Phillips 66 proposed to control SO_2 emissions from SRU No. 1 and SRU No. 3 by using an oxidation tail gas scrubber process, meeting an emissions level not to exceed 167 ppmv, based on a rolling 12-hour average. Based on Phillips 66 proposal and the review of capabilities and incentives specific to this project scenario, the Department has agreed that BACT is as proposed.

CO Emissions

CO emissions occur as a result of the incomplete combustion of hydrocarbons present in the tail gas stream and gaseous fuel (natural gas) combusted in the Sulfur Oxidizer. Improperly tuned gaseous fuel combustion devices and combustion devices operating outside of design levels experience a decrease in combustion efficiency, which can result in increased CO emissions. Additionally, poor maintenance of combustion device burners/combustion air components can result in increased CO emissions due to a decrease in combustion efficiency.

- Oxidation Catalyst

  An oxidation catalyst would experience sulfur poisoning and hence catalyst deactivation when treating exhaust gases from an SRU due to periodic elevated SO_2 emissions that can occur from SRU operations, which would considerably limit the CO removal efficiency of such a catalyst. This option was deemed technically infeasible.

- Good design, operation, and maintenance

  Phillips 66 shall control CO emissions by using good combustion practices for the Sulfur Oxidizer. CO emissions shall not exceed 4.22 lb/hr. The Department assigned source testing as a method to demonstrate this limit.

PM/PM_{10}/$PM_{2.5}$ Emissions

SRU No. 1 is equipped with ABS absorption columns that convert tail gas SO_2 to ABS. The overhead vent stream from these ABS absorption columns (wet scrubbers) is routed to vent gas filters, which partly remove any entrained PM, PM_{10}, and $PM_{2.5}$, before being emitted to the atmosphere.

Due to the fairly unique tail gas treatment configuration utilized, Process Code 50.006 included in the RBLC was not found to be very insightful for evaluating applicable PM control technologies for this SRU. However, SRU No. 1 is effectively equipped with wet scrubbers (the ABS absorption columns located in the tail gas treatment system of the unit), which are followed by high efficiency vent gas filters for PM emissions control. Therefore, SRU No. 1 is already equipped with the best performing PM control technology that would be applicable to this SRU.

The following are the PM, PM_{10}, and $PM_{2.5}$ emission limitations proposed for SRU No. 1 pursuant to ARM 17.8.752. Phillips 66 shall control PM, PM_{10}, and $PM_{2.5}$ emissions from SRU No. 1 by using a high efficiency gas filter after the ABS Absorption Columns (T-101 and T-102) located in this SRU. PM emissions from SRU No. 1 shall not exceed 3.85 lb/hr. PM_{10}/$PM_{2.5}$ emissions from SRU No. 1 shall not exceed 1.61 lb/hr.

The Department applied the same BACT determination to SRU #3.

NO_X Emissions

- Selective Catalytic Reduction (SCR)

  SCR systems can effectively operate at a temperature above 350 °F and below 1,100 °F, with a more refined temperature window dependent on the composition of the catalyst used in the SCR system. At less than 200 °F, the temperature of the exhaust gases from the SRUs would be considerably below any reasonable temperature necessary to effectively operate an SCR system. Considerable heat would need to be added to the exhaust gases.

- Selective Non-Catalytic Reduction (SNCR)

  Even more dependent on an elevated temperature due to the absence of a promoting catalyst, SNCR requires a temperature above 1,600 °F to be effective. At less than 200 °F, the temperature of the exhaust gases from the SRUs would be considerably below any reasonable temperature necessary to effectively operate an SNCR system. Considerable heat would need to be added to the exhaust gases.

- Non-Selective Catalytic Reduction (NSCR)

  NSCR has been applied to nitric acid plants and rich burn (0.3 to 0.5% excess oxygen) and stoichiometric internal combustion engines to reduce NOx emissions. However, the exhaust gases from SRU No. 1 will contain oxygen concentrations considerably higher (>3% and as high as 10-12%) than those necessary to ensure NOx reduction with an NSCR system. Additionally, intermittent elevated levels of SO_2 emissions would potentially result in sulfur poisoning and hence catalyst deactivation in this particular case.

The Department determined that controlling NOx emissions from the SRUs by using Ultra Low NOx Burners in the Sulfur Oxidizer located in the SRUs meets BACT. For a description of Ultra Low NO_X Burner technology, please reference the process heaters section.

IV. Existing Air Quality

Phillips 66 is located at 401 South 23rd Street in Billings, Montana in the NW ¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County. The Laurel SO_2 nonattainment area is about 31.9 kilometers (19.8 miles) southwest from the center of the main operating facility. The Billings SO_2 nonattainment area ends at Interstate Highway I-90, which borders the facility's east boundary.

V. Ambient Air Impact Analysis

On July 25, 2013, a portion of Yellowstone County was designated nonattainment for the 2010 revised National Ambient Air Quality Standards or NAAQS for SO_2. Although Montana disagreed with EPA's conclusion that a nonattainment area in Yellowstone county was appropriate, in accord to EPA's March 24, 2011 Memorandum regarding "Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards", the Department submitted a 5 factor analysis limiting the extent of the nonattainment area boundary based on scientific analyses. The purpose of the 5 factor analysis was to demonstrate that an appropriate nonattainment area boundary would differ from the otherwise default geopolitical boundary of the entirety of Yellowstone County. This demonstration, submitted in Montana's April 3, 2013 letter to EPA, discussed in detail the air quality data, emissions-related data, meteorology, topography, and the juristictional boundaries within the area.

The Department concluded, and EPA agreed, that under a variety of operating scenarios amongst the 7 major SO_2 emitters in the area the observed SO_2 NAAQS violation at the Coburn Road SO_2 Monitoring Station was not attributable to Phillips 66. The Department and EPA's analyses concluded that the Phillips 66 Billings Refinery, including the associated Jupiter facility, did not cause or contriubute to the NAAQS violation and as such it is inappropriate to include the facility within the nonattainment area boundary.

To further this conclusion and pursuant to ARM 17.8.749(3), Phillips 66 provided an ambient air quality impacts analysis, concluding that this project would not cause or contribute to additional exceedances of the SO_2 NAAQS. Phillips 66 based this analysis on review of past emissions at the facility, the meteorology present during periods of higher emissions, the monitored impacts during those periods, and consideration of the level of emissions changes associated with this proposed project. Phillips 66 demonstrated to the Department's satisfaction that this project would not be expected to cause or contribute to an exceedance of the SO_2 NAAQS. This permitting action would allow for an emissions increase in SO_2 of less than 8 lb/hr. This increase is less than the threshold which would trigger PSD/NSR, is less than the Department's default modeling threshold, and represents a 0.5% increase in hourly SO_2 emissions when compared to the hourly average SO_2 emissions from the seven major stationary sources of SO_2 in the Billings/Laurel area.

Further, based on the limited increases for all other pollutants, the Department does not believe this project will cause or contribute to exceedance of any Montana or National Ambient Air Quality Standard.

VI. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, the Department conducted the following private property taking and damaging assessment.

YES	NO	
X		1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?
	X	2. Does the action result in either a permanent or indefinite physical occupation of private property?
	X	3. Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property)
	X	4. Does the action deprive the owner of all economically viable uses of the property?
	X	5. Does the action require a property owner to dedicate a portion of property or to grant an easement? [If no, go to (6)].
		5a. Is there a reasonable, specific connection between the government requirement and legitimate state interests?
		5b. Is the government requirement roughly proportional to the impact of the proposed use of the property?
	X	6. Does the action have a severe impact on the value of the property? (consider economic impact, investment-backed expectations, character of government action)
	X	7. Does the action damage the property by causing some physical disturbance with respect to the property in excess of that sustained by the public generally?
	X	7a. Is the impact of government action direct, peculiar, and significant?
	X	7b. Has government action resulted in the property becoming practically inaccessible, waterlogged or flooded?
	X	7c. Has government action lowered property values by more than 30% and necessitated the physical taking of adjacent property or property across a public way from the property in question?
	X	Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

Based on this analysis, the Department determined there are no taking or damaging implications associated with this permit action.

VII. Environmental Assessment

An environmental assessment, required by the Montana Environmental Policy Act, was completed for this project. A copy is attached.

DEPARTMENT OF ENVIRONMENTAL QUALITY
Permitting and Compliance Division
Air Resources Management Bureau
P.O. Box 200901, Helena, Montana 59620
(406) 444-3490

FINAL ENVIRONMENTAL ASSESSMENT (EA)

Issued To: Phillips 66 Company
Billings Refinery
P.O. Box 30198
Billings, MT 59107-0198

Montana Air Quality Permit Number: 2619-32

Preliminary Determination Issued: December 16, 2014
Department Decision Issued: January 15, 2015
Permit Final: January 31, 2015

1. *Legal Description of Site*: 401 South 23rd Street, Billings, Montana, in the NW¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County.

2. *Description of Project*: In accordance with the preconstruction air quality permitting requirements of the Administrative Rules of Montana (ARM) 17.8.748, Phillips 66 Company submitted a permit application to request authorization from the MT DEQ to implement a project (referred to as the Vacuum Improvement Project) at the refinery. In general, the project proposes physical changes to process units and auxiliary facilities at the refinery in order to provide more optimized operations for a broader spectrum of crude oil slates. These physical changes are primarily related to certain crude distillation, hydrogen production and recovery, fuel gas amine treatment, wastewater treatment, and sulfur recovery equipment and operations.

3. *Objectives of Project*: To provide the means to process a broader spectrum of crude oil slates.

4. *Alternatives Considered*: In addition to the proposed action, the Department also considered the "no-action" alternative. The "no-action" alternative would deny issuance of the air quality preconstruction permit to the proposed facility. However, the Department does not consider the "no-action" alternative to be appropriate because Phillips 66 Company demonstrated compliance with all applicable rules and regulations as required for permit issuance. Therefore, the "no-action" alternative was eliminated from further consideration.

5. *A Listing of Mitigation, Stipulations, and Other Controls*: A list of enforceable conditions, including a BACT analysis, would be included in MAQP #2619-32.

6. *Regulatory Effects on Private Property*: The Department considered alternatives to the conditions imposed in this permit as part of the permit development. The Department determined that the permit conditions are reasonably necessary to ensure compliance with applicable requirements and demonstrate compliance with those requirements and do not unduly restrict private property rights.

7. *The following table summarizes the potential physical and biological effects of the proposed project on the human environment. The "no-action" alternative was discussed previously.*

		Major	Moderate	Minor	None	Unknown	Comments Included
A	Terrestrial and Aquatic Life and Habitats			XX			Yes
B	Water Quality, Quantity, and Distribution			XX			Yes
C	Geology and Soil Quality, Stability and Moisture			XX			Yes
D	Vegetation Cover, Quantity, and Quality			XX			Yes
E	Aesthetics			XX			Yes
F	Air Quality			XX			Yes
G	Unique Endangered, Fragile, or Limited Environmental Resources			XX			Yes
H	Demands on Environmental Resource of Water, Air and Energy			XX			Yes
I	Historical and Archaeological Sites			XX			Yes
J	Cumulative and Secondary Impacts			XX			Yes

SUMMARY OF COMMENTS ON POTENTIAL PHYSICAL AND BIOLOGICAL EFFECTS: The following comments have been prepared by the Department.

A. Terrestrial and Aquatic Life and Habitats

This permit action would allow for increases of pollutants from an existing source of these emissions. MAQP #2619-32 would require that the facility not cause or contribute to exceedances of the National Ambient Air Quality Standards. Impacts to terrestrial and aquatic life and habitats would be expected to be minor.

B. Water Quality, Quantity and Distribution

No surface water drainage pattern is expected to be impacted by the proposed project. All wastewater and stormwater discharges from the proposed project are required to be permitted. Montana Pollutant Discharge Elimination System (MPDES) Permit No. MT-0000256 will be modified to include post-construction wastewater treatment configuration and discharge requirements. Additionally, the City of Billings Significant Industrial User Permit No. 1-13 will require modification to include post-construction wastewater treatment configuration and discharge rates requirements.

Water usage will be required for the new cooling towers to be installed as part of this project. Actual net consumption would be much lower than the circulation rates indicated in the application.

The Department would expect no more than minor impacts to water quality, quantity, and distribution.

C. Geology and Soil Quality, Stability and Moisture

The project will include new construction; however, the project is proposed to occur on industrial property. No unique geological features would be expected to be disturbed.

Increases in emissions from an existing source of emissions may occur. These emissions would be limited under MAQP #2619-32.

Impacts to geology, soil quality, stability, and moisture would be expected to be minor.

D. Vegetation Cover, Quantity, and Quality

Increases in emissions from an existing source of emissions may occur. These emissions would be limited under MAQP #2619-32. Any impacts to vegetation cover, quantity, or quality as a result of these emissions would be expected to be minor, if any discernable amount at all.

Any disturbances associated with construction would be expected to be minor. The Administrative Rules of Montana (ARM 17.8.308(3)) requires that no person shall operate a construction site or demolition project unless reasonable precautions are taken to control emissions of airborne particulate matter. Such emissions of airborne particulate matter from any stationary source shall not exhibit an opacity of 20% or greater averaged over six consecutive minutes. Therefore, any impacts from dust created during construction related activities would be limited, minor, and short lived.

E. Aesthetics

New equipment, including new emissions stacks, would be constructed as part of this project. The new equipment would be installed at an existing industrial facility.

Construction activities and associated equipment would be expected to generate minor levels of noise; however, these activities would be temporary. The operations of the installed equipment are not expected to result in a change to the overall noise level from the refinery.

Impacts to aesthetics would be expected to be minor.

F. Air Quality

MAQP #2619-32 would contain limitations and conditions to ensure the proposed project's increased emissions do not impact ambient air quality above ambient air quality standards. All increases are below Prevention of Significant Deterioration thresholds.

G. Unique Endangered, Fragile, or Limited Environmental Resources

The Department contacted the Montana Natural Heritage Program to request information on any known Montana Species of Concern in the vicinity of the project location. The database search returned 32 species occurrence reports for 14 animal species of concern. The Montana Natural Heritage Program indicated that public release of specific species and location information may jeopardize the welfare of threatened, endangered, or sensitive species. Therefore, this analysis will not discuss specific animals of concern or observed locations. Species of concern in the general area included a wide variety of birds, as well as fish, reptiles, and mammals.

Of importance in the review of impacts to these animals is the currently existing emissions from this source and nearby sources, as well as the level of increase in emissions proposed. As discussed in the ambient air quality analysis section of MAQP 2619-32, the emissions increase of SO_2 represents a 0.5% increase in hourly SO_2 emissions when compared to the hourly average SO_2 emissions from the seven major stationary sources of SO_2 in the Billings/Laurel area. A discernable impact to any species of special concern as a result of this project would not be expected. Further, in consideration of all other pollutants, because the increase in emissions proposed falls below those levels which would trigger Prevention of Significant Deterioration review, because MAQP 2619-32 would limit emissions increases to levels acceptable from an ambient air quality impacts standpoint, and because the project is located at an existing source of these emissions as well as within an industrialized area, any impacts to currently present species of special concern would be expected to be minor as a result of this project.

H. Demands on Environmental Resource of Water, Air and Energy

Minor additions to existing refinery-owned substations are planned to be made to accommodate the increase in electrical demand estimated for the project. No changes or upgrades to the high voltage refinery feeds are anticipated.

Impacts and demands on Water and Air resources was disussed in Section 7.B and 7.F of this environmental assessment. Minor impacts to environmental resource of water, air, and energy would be expected.

I. Historical and Archaeological Sites

The Department contacted the Montana State Historic Preservation Office (SHPO) to request a file search for the presence of historical sites in the area. It is SHPO's position that any structure over fifty years of age is considered historic and potentially eligible for listing on the National Register of Historic Places. SHPO's file search returned several sites. It is SHPO's position that as long as there will be no disturbance or alteration to structures over fifty years of age, that there is low likelihood cultural properties will be impacted. The Department did not consider modification of the refinery itself as likely to impact cultural properties. The Department would expect minor, if any, impacts to historical or archeological sites as a result of this project.

J. Cumulative and Secondary Impacts

No more than minor impacts would be expected to the individual physical and biological considerations above. From a cumulative and secondary impacts standpoint, no more than a minor impact would be expected.

8. *The following table summarizes the potential economic and social effects of the proposed project on the human environment. The "no-action" alternative was discussed previously.*

		Major	Moderate	Minor	None	Unknown	Comments Included
A	Social Structures and Mores			XX			Yes
B	Cultural Uniqueness and Diversity			XX			Yes
C	Local and State Tax Base and Tax Revenue			XX			Yes
D	Agricultural or Industrial Production			XX			Yes
E	Human Health			XX			Yes
F	Access to and Quality of Recreational and Wilderness Activities			XX			Yes
G	Quantity and Distribution of Employment			XX			Yes
H	Distribution of Population			XX			Yes
I	Demands for Government Services			XX			Yes
J	Industrial and Commercial Activity			XX			Yes
K	Locally Adopted Environmental Plans and Goals			XX			Yes
L	Cumulative and Secondary Impacts			XX			Yes

SUMMARY OF COMMENTS ON POTENTIAL ECONOMIC AND SOCIAL EFFECTS: The following comments have been prepared by the Department.

A. Social Structures and Mores

The permitting action would not be expected to cause a disruption to any native or traditional lifestyles or communities (social structures or mores) in the area. The nature of the site will not be changed, and additional employment is not expected. Any impacts to social structures and mores would be expected to be minor.

B. Cultural Uniqueness and Diversity

The permitting action would not be expected to cause a change in the cultural uniqueness and diversity of the area because the land is currently used as a petroleum refinery and land use would not be changing. The nature of the site will not be changed, and additional employment is not expected. Any impacts to cultural uniqueness and diversity would be expected to be minor.

C. Local and State Tax Base and Tax Revenue

No permanent new employees would be expected for this project but contractors would likely be on-site for construction and installation. Overall crude refining capacity is not expected to increase. Therefore, any impacts to the local and state tax base and tax revenue would be expected to be minor.

D. Agricultural or Industrial Production

The permitting action would not result in a reduction of available acreage of any agricultural land as the land disturbed is at the refinery site. Changes in emissions of air pollutants would not be expected to impact agricultural productivity. Any impacts to industrial production would be expected to be minor, as no increase in refinery capacity of process units is proposed.

E. Human Health

As described in Section 7.F and 7.H of this environmental assessment, impacts on air quality, water quality, and energy demands are expected to be minor. No more than minor impacts to human health would be expected as a result of this permitting action.

F. Access to and Quality of Recreational and Wilderness Activities

The project would not be expected to result in any changes in access to and quality of recreational and wilderness activities. Any impacts to recreational and wilderness activities would be expected to be minor.

G. Quantity and Distribution of Employment

No change in the number of permanent employees currently onsite would be anticipated as a result of this permitting action. The construction process would require additional construction related work. Any impacts to the quantity and distribution of employment would be expected to be minor.

H. Distribution of Population

This permitting action does not involve any change that would be expected to affect the location, distribution, density, or growth rate of the human population. The distribution of population would not be expected to change as a result of this action. Any impacts would be expected to be minor.

I. Demands for Government Services

The demands on government services would experience a minor impact. The primary demand on government services would be the acquisition of the appropriate permits by the facility and compliance verification with those permits.

J. Industrial and Commercial Activity

An increase in the refinery's overall capacity is not expected. Construction activity would be required. Impacts to industrial and commercial activity would be expected on a temporary basis.

K. Locally Adopted Environmental Plans and Goals

Phillips 66 would be required to continue to comply with the State Implementation Plan and Federal Implementation Plan and associated stipulations for the Billings/Laurel area. The Department is not aware of any locally adopted environmental plans and goals which this project would interfere with.

L. Cumulative and Secondary Impacts

The impacts to the individual social and economic considerations above would be expected to be minor. From a cumulative viewpoint, and in consideration of secondary impacts, impacts would be expected to be minor.

Recommendation: No Environmental Impact Statement (EIS) is required. The current permitting action is for the construction and operation of the Vacuum Improvement Project at Phillips 66 Company's Billings Refinery. MAQP #2619-32 would include conditions and limitations to ensure the facility will operate in compliance with all applicable rules and regulations. In addition, there are no significant impacts associated with this proposal.

Other groups or agencies contacted or which may have overlapping jurisdiction: Montana Historical Society – State Historic Preservation Office, Natural Resource Information System – Montana Natural Heritage Program

Individuals or groups contributing to this EA: Department of Environmental Quality – Air Resources Management Bureau, Montana Historical Society – State Historic Preservation Office, Natural Resource Information System – Montana Natural Heritage Program

EA prepared by: Shawn Juers
Date: November 28, 2014